NUCLEAR ENERGY INSTITUTE
NUCLEAR CARBON-FREE ENERGY

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Via Electronic Submission

Subject: NEI's Comments on Proposed Section 45V Clean Hydrogen Regulations (REG-117631-23)

To Whom It May Concern:

On behalf of our members, the Nuclear Energy Institute (NEI) submits the following comments in response to the above-referenced rulemaking addressing the clean hydrogen production credit established by the Inflation Reduction Act of 2022 (IRA).[1] NEI is the trade association for the commercial nuclear technologies industry, and our mission is to promote the use and growth of nuclear energy through efficient operations and effective policy. NEI has more than 300 members, including companies that own or operate nuclear power plants, reactor designers and advanced technology companies, architectural and engineering firms, fuel suppliers and service companies, consulting services and manufacturing companies, companies involved in nuclear medicine and nuclear industrial applications, radionuclide and radiopharmaceutical companies, universities and research laboratories, labor unions, and international electric utilities.

As discussed in the attached comments, NEI strongly opposes the incrementality requirement in the proposed rule. The incrementality requirement has no basis in the IRA. Congress explicitly enabled existing nuclear facilities to receive the clean hydrogen production tax credit by providing that section 45U (which is only available to existing

[1] Dep't of the Treasury, Notice of Proposed Rulemaking and Notice of Public Hearing, Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property, 88 Fed. Reg. 89,220 (Dec. 26, 2023).

reactors) and section 45V can be claimed at the same site. The statutory text and structure confirm that an incrementality requirement exceeds Treasury's authority. Textually, Congress made the credit broadly available for "any" qualified clean hydrogen without distinguishing between existing and new resources, and it repeatedly directed Treasury to focus only on emissions related to the hydrogen production "process," which does not include attenuated effects beyond the "point of production" like emissions on the electric grid resulting from power used by other consumers for other purposes. Consideration of such emissions also does not accord with the definition of "lifecycle greenhouse gas emissions" in the Clean Air Act and fundamentally departs from the current GREET model in a manner Congress did not intend. Structurally, the statute contains numerous provisions that are explicitly limited to facilities of a particular age (*i.e.*, "vintage requirements"). Those provisions cannot be reconciled with an agency-created incrementality requirement. As such, any imposition of an incrementality requirement is arbitrary and capricious. The incrementality requirement is further squarely foreclosed by the major questions doctrine, which the U.S. Supreme Court has repeatedly applied to limit agency regulatory authority—particularly when, as here, the agency is not expert in the area it is seeking to regulate.

Moreover, the incrementality requirement countermands Congress's purpose in enacting section 45V. Congress sought to jump-start the clean hydrogen industry in the United States, recognizing that the nascent industry needed significant governmental support, and that clean hydrogen is necessary to decarbonize hard-to-electrify industrial sectors of the economy. As the Department of Energy has recognized, a large near-term ramp-up of hydrogen production is needed to achieve the administration's mid-century carbon-reduction goals. Yet the proposed rule myopically focuses on avoiding any short-term increase in carbon emissions resulting from what it calls "induced emissions"—shorthand for reliance on other generation sources by other users on the grid—without even evaluating the negative impact the incrementality requirement will have on hydrogen deployment. The proposed rule thus fails to consider a crucially important part of the picture—indeed, it fails to consider Congress's primary aim in passing the statute.

The incrementality requirement also is arbitrary and capricious for several other reasons. Key among them, Treasury's assumption that hydrogen production using new clean generation will not produce any induced emissions, while hydrogen production using existing clean generation necessarily will, is unsupported and wrong. On the one hand, prevailing economic and policy conditions all but ensure that little-to-no new clean generation will be "incremental":

- In much of the country, there is already more demand for clean generation than can be supplied. In those regions, new clean generation and existing clean generation are identically situated: once online, either one would be serving other load on the grid if they were not being used to produce hydrogen. Accordingly, their use to produce hydrogen results in the same "induced emissions."

- In other areas of the country, new clean generation is economic or built as part of the traditional vertically integrated regulated utility framework and would enter service regardless of the section 45V credit. In these regions, the section 45V credit does not bring about any incremental clean generation—it simply results in new clean generation that would otherwise be serving the grid being used for hydrogen production instead.

From the standpoint of grid emissions, using a new resource for hydrogen production that would otherwise be used somewhere else on the grid is no different than using an existing resource for hydrogen production that would otherwise be used somewhere else on the grid. Yet the proposed rule fails to grapple with this reality.

By contrast, the most substantial thing that hydrogen producers can do to mitigate grid emissions is to take service from nuclear plants that otherwise may retire. U.S. Energy Information Administration data shows that more than 20 percent of the existing nuclear fleet may retire by 2040, as various state support programs sunset later this decade and the section 45U nuclear production tax credit sunsets in at the end of 2032. Enabling nuclear plants to serve hydrogen producers receiving section 45V credits may make the difference in keeping these large, clean generators online. Thus, if anything is "incremental," it is powering hydrogen production with nuclear plants that will need to be relicensed but are facing a revenue cliff in the near future. The proposed rule acknowledges that avoiding retirements can be incremental, and seeks comment on a framework for considering retirements, but its implementation proposals fall far short of providing hydrogen producers with adequate credit for avoided nuclear retirements.

The proposed rule also fails to account for the expectation that the grid will get cleaner with time, meaning that induced grid emissions will lessen as time passes—especially in states that have mandated 100 percent clean energy goals. The three-year lookback provision that Treasury proposes for the incrementality requirement also is arbitrary; the proposal does not explain why a three-year old resource is any different from any other existing resource from the standpoint of induced emissions.

Finally, to the extent Treasury nonetheless adopts an incrementality requirement in the final regulations, it should revise the requirement in certain ways. First, Treasury should allow at least ten percent of a company's existing carbon-free generation, measured at the owner level rather than the facility level, to be used for qualifying hydrogen production for facilities that begin construction after Dec. 31, 2026. Second, Treasury should deem a nuclear unit that extends its operating license from the Nuclear Regulatory Commission to be incremental and therefore eligible to be used to produce hydrogen qualifying for the maximum tax credit. These two proposals are consistent with an incrementality approach and would appropriately recognize the substantial risk that a significant quantity of nuclear capacity will retire once the section 45U nuclear production tax credit sunsets in 2033. Third, Treasury should adopt a “begin construction” exception to incrementality that would allow all hydrogen projects that are under construction by Dec. 31, 2026, to use existing resources to produce clean hydrogen through the term of the section 45V tax credit. This exception will help to kickstart the hydrogen industry and ensure that an incrementality requirement does not undermine Congress’s $8 billion investment in hydrogen hubs, many of which contemplate sourcing electricity from existing clean resources.

Thank you in advance for your consideration of NEI’s comments. NEI appreciates the opportunity to provide the industry’s views. If you have any questions or require additional information, please feel free to contact me and Benton Arnett (bta@nei.org).

Regards,

Jonathan M. Rund

Attachment: The Nuclear Energy Institute’s Comments on the Proposed Section 45V Clean Hydrogen Regulations (REG-117631-23)

The NorthBridge Group’s Report “Assessing the Incrementality Requirement Proposed in Treasury’s 45V Regulations”

THE NUCLEAR ENERGY INSTITUTE'S COMMENTS ON THE PROPOSED SECTION 45V CLEAN HYDROGEN REGULATIONS (REG-117631-23)

I. Executive Summary

The Nuclear Energy Institute ("NEI") submits these comments in response to the notice of proposed rulemaking addressing the clean hydrogen production credit established by the Inflation Reduction Act of 2022 ("IRA").[1] NEI is the trade association for the commercial nuclear technologies industry, and our mission is to promote the use and growth of nuclear energy through efficient operations and effective policy. NEI has more than 300 members, including companies that own or operate nuclear power plants, reactor designers and advanced technology companies, architectual and engineering firms, fuel suppliers and service companies, consulting services and manufacturing companies, companies involved in nuclear medicine and nuclear industrial applications, radionuclide and radiopharmaceutical companies, universities and research laboratories, labor unions, and international electric utilities. NEI strongly opposes the incrementality requirement in the proposed rule.

The incrementality requirement has no basis in the IRA. Congress explicitly enables existing nuclear facilities to receive the clean hydrogen production tax credit by stacking § 45U and § 45V. The statutory text and structure confirm that an incrementality requirement exceeds Treasury's authority. Textually, Congress made the credit broadly available for "any" qualified clean hydrogen without distinguishing between existing and new resources, and it repeatedly directed Treasury to focus only on emissions related to the hydrogen production "process," which does not include attenuated effects beyond the "point of production" like emissions on the electric grid resulting from power used by other consumers for other purposes. Consideration of such emissions also does not accord with the definition of "lifecycle greenhouse gas emissions" in the Clean Air Act ("CAA") and fundamentally departs from the current GREET model in a manner Congress did not intend. Structurally, the statute contains numerous provisions that are explicitly limited to facilities of a particular age (i.e., "vintage requirements"). Those provisions cannot be reconciled with an agency-created incrementality requirement. As such, any imposition of an incrementality requirement is arbitrary and capricious. The incrementality requirement is further squarely foreclosed by the major questions doctrine, which the U.S. Supreme Court has repeatedly applied to limit agency regulatory authority—particularly when, as here, the agency is not expert in the area it is seeking to regulate.

Moreover, the incrementality requirement countermands Congress's purpose in enacting § 45V. Congress sought to jump-start the clean hydrogen industry in the United States, recognizing that the nascent industry needed significant governmental support, and that clean hydrogen is necessary to decarbonize hard-to-electrify industrial sectors of the economy. As the Department of Energy has recognized, a large near-term ramp-up of hydrogen production is needed to achieve the Administration's mid-century carbon-reduction goals. Yet the proposed rule myopically

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[1] *See* Dep't of the Treasury, Notice of Proposed Rulemaking and Notice of Public Hearing, Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property, 88 Fed. Reg. 89,220 (Dec. 26, 2023) ("NPRM").

focuses on avoiding any short-term increase in carbon emissions resulting from what the proposed rule calls "induced emissions"—shorthand for reliance on other generation sources by other users on the grid—without even evaluating the negative impact the incrementality requirement will have on hydrogen deployment. The proposed rule fails to consider a crucially important part of the picture—indeed, it fails to consider Congress's primary aim in passing the statute.

The incrementality requirement also is arbitrary and capricious for several other reasons. In particular, Treasury's assumption that hydrogen production using new clean generation will not produce any induced emissions, while hydrogen production using existing clean generation necessarily will, is unsupported and wrong. In much of the country, there is already more demand for clean generation than can be supplied. In those regions, new clean generation and existing clean generation are identically situated: once online, either one would be serving other load on the grid if they were not being used to produce hydrogen. Accordingly, using either to produce hydrogen results in the same "induced emissions." In other areas of the country, new clean generation is economic or built as part of the traditional vertically integrated regulated utility framework and would enter service regardless of the § 45V credit. In these regions, the § 45V credit does not bring about any incremental clean generation—it simply results in new clean generation that would otherwise be serving the grid being used for hydrogen production instead. From the standpoint of grid emissions, using a new resource for hydrogen production that would otherwise be used somewhere else on the grid is no different than using an existing resource for hydrogen production that would otherwise be used somewhere else on the grid. Yet the proposed rule fails to grapple with this reality.

The most substantial thing that hydrogen producers can do to mitigate grid emissions is to take service from a nuclear power generator that otherwise may retire. U.S. Energy Information Administration ("EIA") data shows that more than 20 percent of the existing nuclear fleet may retire by 2040. Various state support programs sunset later this decade, and the nuclear production tax credit sunsets at the end of 2032, placing nuclear plants in the same circumstances that led more than one-dozen reactors to retire in the decade leading up to the passage of the IRA. Enabling nuclear plants to serve hydrogen producers receiving § 45V credits may make the difference in keeping these large, clean generators online. Thus, if anything is "incremental," it is using existing nuclear plants to power hydrogen production. The proposed rule acknowledges that avoiding retirements can be incremental, and seeks comment on a framework for considering retirements. But its proposed implementation proposals fall far short of providing hydrogen producers with adequate credit for avoided nuclear retirements.

The proposed rule also fails to account for the expectation that the grid will get cleaner with time, meaning that induced grid emissions will lessen as time passes—especially in states that have mandated 100 percent clean energy goals. The three-year lookback provision that Treasury proposes for the incrementality requirement also is arbitrary; the proposed rule does not explain why a three-year old resource is any different from any other existing resource from the standpoint of induced emissions.

Finally, to the extent Treasury nonetheless adopts an incrementality requirement in the final regulations, it should revise the requirement in certain ways. First, Treasury should allow at least 10 percent of a company's existing carbon-free generation, measured at the owner level rather than the facility level, to be used for qualifying hydrogen production for facilities that begin construction after Dec. 31, 2026. Second, Treasury should deem a nuclear unit that extends its operating license from the Nuclear Regulatory Commission ("NRC") to be incremental and therefore eligible to be used to produce hydrogen qualifying for the maximum tax credit. These two proposals are consistent with an incrementality approach and would appropriately recognize the substantial risk that a significant quantity of nuclear capacity will retire once the nuclear production tax credit sunsets at the end of 2032. Third, Treasury should adopt a "begin construction" exception to incrementality that would allow all hydrogen projects that are under construction by Dec. 31, 2026, to use existing resources to produce clean hydrogen through the term of the § 45V tax credit. This exception will help to kickstart the hydrogen industry and ensure that an incrementality requirement does not undermine Congress's $8 billion investment in hydrogen hubs, many of which contemplate sourcing electricity from existing clean resources.

II. Treasury Lacks Statutory Authority to Adopt an Incrementality Requirement.

Congress expressly intended for existing nuclear resources to be eligible for the clean hydrogen production tax credit in § 45V. The plain text and structure of the IRA make clear that Treasury lacks authority to impose an incrementality requirement for the tax credit. And the major questions doctrine cuts firmly against Treasury and the Internal Revenue Service, which lack expertise in the power sector, interpreting a narrow provision in such an expansive way without clear congressional authorization.[2] Accordingly, the incrementality requirement should be removed from the final regulations.

A. Congress Expressly Intended for Existing Nuclear Resources to Be Eligible for § 45V Tax Credits.

The statute leaves no doubt that existing nuclear resources are eligible for the hydrogen production tax credit—a result directly at odds with the incrementality requirement in the proposed regulations. "A statute should be construed so that effect is given to all of its provisions, so that no part will be inoperative or superfluous, void or insignificant."[3] Here, § 45U establishes a nuclear production tax credit available only to nuclear facilities placed into service prior to the enactment of the IRA. In § 45U(c)(2), Congress incorporated special rules set forth in § 45(e)(13) that allow nuclear facilities receiving credits under § 45U to use the electricity they generate to produce clean hydrogen receiving credits under § 45V. If the § 45V credits were limited to "incremental" resources, then § 45U(c)(2) (incorporating § 45(e)(13)) would be superfluous, as there would be no facilities that could receive both § 45U credits and § 45V credits. Congress would not have established a link between § 45U and § 45V if it intended to preclude existing nuclear facilities from receiving § 45V credits.

[2] *Util. Air Regulatory Grp. v. EPA*, 573 U.S. 302, 324 (2014) (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 160 (2000)).

[3] *Hibbs v. Winn*, 542 U.S. 88, 101 (2004).

Some have argued in response that the explicit provision for stacking these two credits does not undermine incrementality because existing nuclear plants claiming § 45U credits could still be eligible for § 45V by producing additional clean energy above their traditional baselines to power grid-connected electrolyzers.[4] However, under the proposed rule, uprating would yield § 45V credits only to the extent of the uprate. Section 45U credits—which apply to existing nuclear capacity—are not available for uprated capacity. Instead, the uprated portion would qualify for the clean electricity production credit in § 45Y.[5] Because incremental production generated with uprated capacity would receive credits under § 45Y rather than § 45U, an incrementality requirement would render § 45U(c)(2) superfluous.

Moreover, there is simply nothing in the statute indicating that existing nuclear plants would need to act in this fashion to receive credits under § 45V. To the contrary, the structure of the statute affirmatively disproves that creative interpretation. Where Congress wanted to limit a tax credit to the portion of a facility that is uprated, it did so expressly—as it did with respect to existing nuclear plants in § 45Y.[6] Similarly, § 45(c)(8) defines qualified hydropower production for purposes of the renewable electricity production credit to be limited to uprated capacity: "In the case of any hydroelectric dam which was placed in service on or before the date of enactment of this paragraph," the credit is limited to the "*incremental* hydropower production for the taxable year," which is defined as the portion of production "attributable to the efficiency improvements or additions of capacity placed in service after the enactment of this paragraph."[7] No such language is present in § 45V.

B. The Plain Text of § 45V Forecloses an Incrementality Requirement.

In addition, the text of § 45V sets forth a detailed framework for the clean hydrogen production tax credit that repeatedly forecloses an incrementality requirement. Under § 45V(a), the production tax credit is equal to the product of (1) the "kilograms of qualified clean hydrogen produced by the taxpayer during such taxable year at a qualified clean hydrogen production facility during the 10-year period beginning on the date such facility was originally placed in service," and (2) the "applicable amount" with respect to such hydrogen.[8] Under § 45V(b)(1), the "applicable amount" is equal to the "applicable percentage" multiplied by $0.60 (or $3.00 if the prevailing wage and apprenticeship requirements are met).[9] The "applicable percentages" are outlined in

[4] *See, e.g.*, Comment Letter from Clean Air Task Force and Natural Resources Defense Council to Department of the Treasury, Notice 2022-49, at 14 (Apr. 10, 2023) ("CATF/NRDC April Comment Letter").

[5] *See* 26 U.S.C. § 45Y(c).

[6] *See Id.* § 45Y(b)(1)(C) (providing that the term "qualified facility" will include existing facilities, "but only to the extent of the increased amount of electricity produced at the facility by reason of . . . [a]ny additions of capacity which are placed in service after December 31, 2024").

[7] *Id.* § 45(c)(8)(A)(i), (B)(i).

[8] *Id.* § 45V(a).

[9] *Id.* § 45V(b)(1), (e)(1).

§ 45V(b)(2) and create different tiers that link the amount of the hydrogen production tax credit to the "lifecycle greenhouse gas emissions" produced during the production of clean hydrogen.[10]

Section 45V(c)(1)(A) defines "lifecycle greenhouse gas emissions" by cross-reference to CAA § 211(o)(1)(H), subject to important limitations in § 45V(c)(1)(B) specifying that such emissions "shall only include emissions through the point of production (well-to-gate), as determined under the most recent Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (commonly referred to as the 'GREET model') developed by Argonne National Laboratory ["ANL"], or a successor model (as determined by the Secretary)."[11] Reading § 211(o)(1)(H) as qualified by § 45V, the term "lifecycle greenhouse gas emissions" in the clean hydrogen context therefore means the "aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes)" "only . . . through the point of production (well-to-gate), as determined under the most recent [GREET] model developed by Argonne National Laboratory, or a successor model (as determined by the Secretary)."[12]

An incrementality requirement appears nowhere in this statutory scheme. Nonetheless, the proposed regulations read as an incrementality requirement—albeit without identifying a clear statutory basis for doing so.[13] No such basis exists. Treasury instead relies on a letter provided by EPA to justify the incrementality requirement. But analysis of an agency's authority must begin with the statute itself. Here, multiple aspects of the text and structure of § 45V unambiguously foreclose Treasury from imposing an incrementality requirement.

(1) "Produced Through a Process." First, Congress directed Treasury to focus narrowly on the hydrogen production process, which does not include attenuated effects like induced grid emissions. As noted, the production tax credit applies in tiered fashion to any "qualified clean hydrogen." Congress defined "qualified clean hydrogen" as follows: "Qualified clean hydrogen" is "hydrogen which is *produced through a process* that results in a lifecycle greenhouse gas emissions rate of not greater than 4 kilograms of CO_{2e} per kilogram of hydrogen."[14] The proposed regulations incorporate this statutory definition.[15]

This statutory limitation to any hydrogen that is "produced through a process" that yields "lifecycle greenhouse gas emissions" below specified thresholds makes clear that the salient

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10 *Id.* § 45V(b)(2)(A)-(D).

11 *Id.* § 45V(c)(1)(A), (B).

12 42 U.S.C. § 7545(o)(1); 26 U.S.C. § 45V(c)(1)(A)-(B).

13 *See* NPRM, 88 Fed. Reg. at 89,229-32 (discussing incrementality without asserting any specific statutory basis for it).

14 26 U.S.C. § 45V(c)(2)(A) (emphasis added). The statute also provides that the hydrogen must be produced (i) in the United States or a U.S. territory; (ii) in the ordinary course of a trade or business of the taxpayer; and (iii) for sale or use. These limitations again show that where Congress sought to limit availability of § 45V, it knew how to say so.

15 *See* NPRM, 88 Fed. Reg. at 89,246; proposed regulation § 1.45V-1(a)(9)(i).

question for Treasury is the narrow, technical issue of how an individual producer goes about producing clean hydrogen.[16] The word "process" means "[a] series of operations performed in the making or treatment of a product."[17] In adopting this provision, Congress was distinguishing between new processes for producing clean hydrogen that differed from conventional processes like steam-methane reforming, in which natural gas reacts with steam in the presence of a catalyst, producing carbon dioxide.[18] Emissions from direct inputs to the production process, such as electricity usage, thus may be considered under the statute. For a hydrogen producer using zero-emissions electricity for electrolysis, however, the "process" through which hydrogen is produced is the same regardless of whether the zero-emissions electricity comes from an existing generator or a new one.

By contrast, the statute's focus on the technical process by which clean hydrogen is produced does not encompass any consideration of "induced emissions," that is, emissions resulting from the activities of other users of the electric grid. Such emissions are speculative and uncertain indirect effects not proximately caused by the particular process by which hydrogen is produced.[19] Emissions produced by other power plants dispatched to meet other consumers' needs are not part of a taxpayer's hydrogen production "process." Treasury's consideration of these emissions in the proposed regulations goes well beyond the cabined inquiry into the production process that Congress specified.

After all, every activity has an upstream emissions profile that encompasses a potentially infinite variety of indirect emissions. Those could include the emissions associated with the transportation that workers used to arrive at the plant; emissions associated with the manufacture of various physical components of the plant; or even with the building of roads that lead to the plant. Congress recognized that all of these upstream emissions could not reasonably be accounted for, and it therefore limited the inquiry to those emissions caused by the "process" by which hydrogen is produced. Congress's use of that term screens out consideration of attenuated effects

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16 As discussed in greater detail below, the term "lifecycle greenhouse gas emissions," as defined in § 45V and via cross-reference to CAA § 211(o)(1)(H), confirms that an incrementality requirement is not permissible.

17 *American Heritage Dictionary of the English Language*, at 1404 (5th ed. 2011); *see also Oxford Pocket American Dictionary of Current English*, at 630 (2002) (defining "process" as "a course of action or proceeding, esp. a series of stages in manufacture or some other operation").

18 H.R. 5192, a precursor to § 45V introduced in the 117th Congress, suggests that Congress was focused on this distinction between new and conventional processes. That bill made the tax credit available to "any qualified clean hydrogen which is produced through a process that, *as compared to hydrogen produced by steam-methane reforming*, achieves a percentage reduction in lifecycle greenhouse gas emissions" set at various specified thresholds.

19 An analogy can be drawn here to case law under the National Environmental Policy Act, which has recognized that a but-for relationship between a proposed action and an indirect effect is insufficient. Rather, proximate causation must be shown, in part because indirect effects are highly speculative, uncertain, and insufficiently specific to be considered. *See, e.g.*, *Dep't of Transp. v. Public Citizen*, 541 U.S. 752, 767 (2004); *City of Dallas v. Hall*, 562 F.3d 712, 719 (5th Cir. 2009). Here, too, Congress was plainly focused on effects that are readily quantifiable, as seen in its further specification of the precise model to be used to quantify lifecycle greenhouse gas emissions. 26 U.S.C. § 45V(c)(1)(B).

occurring separate from the hydrogen production process itself, over which the hydrogen producer has no control and for which it has no responsibility.

Indeed, a few examples demonstrate why consideration of "induced emissions"—*i.e.*, the emissions resulting from the activities of power plants meeting other electricity consumers' needs elsewhere on the grid—is inconsistent with the statute's focus on the hydrogen production process. Imagine an electrolyzer that runs 24 hours a day sourcing electricity behind-the-meter from a nuclear plant that operates all day. Demand elsewhere on the grid will rise and fall throughout the day, and the grid's emissions will change throughout the day as different plants are dispatched to meet demand. It would make little sense, as a matter of plain English, to say that the hydrogen production process, which is exactly the same all day long, itself emits more carbon in the afternoon than in the evening. To take another example, suppose that in the first year of the hydrogen producer's operation, there is an economic recession and overall grid demand is low, resulting in lower overall carbon intensity of the grid. In the second year of operation, there is an economic recovery, resulting in significantly increased grid demand and the dispatch of more carbon emitting plants. As a matter of ordinary language, it again makes no sense to attribute the increased emissions to the hydrogen production process, which has remained exactly the same. Yet the incrementality requirement would do exactly that, by assigning grid average emissions to the hydrogen producer, despite the fact that it has sourced electricity exclusively from a zero-emitting nuclear plant.

To take one further example, suppose that a state required a carbon emitter to obtain an emissions credit. If a hydrogen producer sources electricity from clean generation, and that leads other grid users to source their electricity from increased dispatch of a carbon-emitting unit, no one would think that the clean hydrogen producer should be responsible for obtaining the emitting unit's emissions credit. That unit's emissions are attributable to the unit and to the grid users actually using its electricity.

These examples also underscore that an incrementality requirement is particularly countertextual in the context of a behind-the-meter electrolyzer that is not connected to the grid at all. The emissions profile of hydrogen produced using electricity from a specific electric generation source that supplies electricity via direct connection to the electrolyzer without flowing through the grid is clear: it reflects the emissions of the generator powering the behind-the-meter electrolyzer. The hydrogen production process does not rely on grid energy at all, so grid emissions cannot logically be attributed to it. Notably, earlier comments from NGOs supported treating behind-the-meter electrolyzers differently than those that are grid-connected, and attributing to the former the emissions profile of the specific unit that is powering it.[20] The Department of Energy's Lift-Off Report likewise presumed the eligibility of electrolyzers powered by dedicated zero-

[20] Response of the Princeton University Zero-Carbon Energy Systems Research and Optimization Laboratory (ZERO Lab), at 7 (Dec. 2, 2023), https://downloads.regulations.gov/IRS-2022-0029-0071/attachment_1.pdf ("[A]ny electricity generated by behind-the-meter resources and consumed in the process of hydrogen production should be considered to have embodied emissions equivalent to those of the installed resources."); Natural Resources Defense Council Comment Letter to Treasury, Notice 2022-58, at 2 (Dec. 2, 2022) ("NRDC December Comment") ("Producers of electrolytic hydrogen that use primarily on-site, zero-carbon electricity should immediately qualify.").

carbon electricity sources, including existing nuclear.[21] Even if Treasury retains the incrementality requirement for grid-connected electrolyzers, it must treat behind-the-meter electrolyzers using specific generation resources differently and attribute to that hydrogen the emissions profile of the specific generation resource actually powering the electrolyzer.

(2) CAA Section 211(o)(1)(H) and the "Point of Production." Other definitional provisions in § 45V reinforce the same conclusion. Treasury primarily relies on a letter from EPA ("EPA Letter") to justify an incrementality requirement based on § 45V's cross-reference to § 211(o)(1)(H) of the CAA, which provides a definition of "lifecycle greenhouse gas emissions."[22] The reasoning of the EPA Letter echoes a previous comment submitted by the Clean Air Task Force ("CATF") and the Natural Resources Defense Council ("NRDC"), which argued that the "IRA incorporates section 211(o)'s definition of 'lifecycle greenhouse gas emissions,'" and that this definition "makes clear that Treasury must consider the systemwide—and not just project-specific—emissions impacts of hydrogen production."[23] The argument presented in the EPA Letter is wrong. Congress incorporated this cross-reference to provide a starting point for the fuel lifecycle emissions analysis (namely, from "feedstock generation or extraction"), but the statute expressly provides the end point of that analysis: the "point of production." This cross-reference, even considered in light of the recent EPA Letter that Treasury references in the proposed rule, therefore does not provide a statutory basis for an incrementality requirement.

Section 45V(c)(1)(A) provides that "[s]ubject to subparagraph (B), the term 'lifecycle greenhouse gas emissions' has the same meaning given such term under subparagraph (H) of section 211(o)(1) of the Clean Air Act (42 U.S.C. § 7545(o)(1)), as in effect on the date of enactment of this section."[24] In relevant part, § 211(o)(1)(H) of the CAA in turn defines "lifecycle greenhouse gas emissions" for purposes of EPA's Renewable Fuel Standard ("RFS") program as the "aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes) . . . related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution."[25]

This cross-reference provides meaningful guidance as to the starting point of the fuel lifecycle emissions analysis. For example, the lifecycle emissions of blue hydrogen—which is produced using a natural gas feedstock, through a process of steam methane reformation and carbon capture—would include fugitive methane emissions that occur when natural gas is gathered. For electrolytic hydrogen, produced using water as a feedstock, lifecycle emissions

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[21] U.S. Dep't of Energy, *Pathways to Commercial Liftoff: Clean Hydrogen*, at 12 (Mar. 2023), https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf ("Pathways Report") ("Dedicated zero-carbon electricity: Non-emitting energy sources such as solar, wind, nuclear, and hydro can produce hydrogen with carbon intensities lower than 0.45 kg CO2e/kg H2, qualifying for the full production tax credit (PTC, $3/kg "of H2).").

[22] 26 U.S.C. § 45V(c)(1)(A).

[23] CATF/NRDC April Comment Letter at 4.

[24] 26 U.S.C. § 45V(c)(1)(A).

[25] 42 U.S.C. § 7545(o)(1)(H).

would include any emissions associated with securing and transporting the water and its diversion from alternative uses. But § 211(o)(1)(H)'s reference to "significant indirect emissions" does *not* provide support for an incrementality requirement, contrary to the position EPA purports to defend in its six-page letter to Treasury.[26] That is so for several reasons.

First, Congress explicitly specified in § 45V(c)(1)(A) that only a truncated version of EPA's definition of "lifecycle greenhouse gas emissions" would apply. It did so by beginning subparagraph (A) with the qualification that the incorporation of EPA's definition was "[s]ubject to subparagraph (B)."[27] Subparagraph (B) then specifies that "[t]he term 'lifecycle greenhouse gas emissions' *shall only* include emissions *through the point of production* (well-to-gate), as determined under the most recent [GREET] model . . . developed by Argonne National Laboratory, or a successor model (as determined by the Secretary)."[28] These portions of subparagraphs (A) and (B) can only be read as Congress making double sure that Treasury is *not* to consider the "full fuel lifecycle" referenced in § 211(o)(1)(H), but instead focus only on emissions up to the "point of production."[29] It is essentially undisputed that the full EPA interpretation from § 211(o)(1)(H) cannot be imported. Even those favoring an incrementality requirement concede that this prefatory language in § 45V(c)(1)(A) "slightly narrows the prevailing interpretation of section 211(o)."[30] But the narrowing is more than slight.

This prefatory language underscores Congress's focus on the production process and rules out attributing emissions to the hydrogen producer that result from factors exogenous to the production process, such as the entry and exit of other power generators and power users from the market over time. These grid emissions—which will change over time and result from independent decisions made by power producers and other grid users downstream from the hydrogen production "gate," and will be driven by many factors other than the additional load caused by hydrogen production—have at most an attenuated connection to how a producer is making clean hydrogen "through the point of production." Consideration of these broad systemwide changes is contrary to the statute's command to "only" consider "emissions through the point of production."

Second, the EPA Letter is remarkably qualified and cannot satisfy § 45V(c)(1)(A)'s requirement that Treasury apply the "same meaning given" to "lifecycle greenhouse gas emissions" in § 211(o)(1)(H) "as in effect on the date of [§ 45V's] enactment."[31] By using that language, Congress carefully specified that Treasury did not have any license to depart from the meaning of "lifecycle greenhouse gas emissions" that EPA was already applying. Congress even repeated this constraint by further specifying that Treasury must apply the same meaning "in effect

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[26] *See* NPRM, 88 Fed. Reg. at 89,228 (incorporating EPA Letter).

[27] 26 U.S.C. § 45V(c)(1)(A).

[28] *Id*. § 45V(c)(1)(B) (emphasis added).

[29] *Id.*

[30] CATF/NRDC April Comment Letter at 10.

[31] 26 U.S.C. § 45V(c)(1)(A).

on the date of enactment of this section."[32] Yet nowhere in the EPA Letter does EPA actually say that *EPA* has ever included induced grid emissions in implementing § 211(o). Indeed, EPA does not, and indeed cannot, say that consideration of induced grid emissions is compelled for its RFS program—nor can the plain text of § 211(o)(1)(H) bear that interpretation regardless of how EPA has interpreted it. The bulk of EPA's two pages of analysis relies on inferences from its 2010 RFS rulemaking (the "RFS2 rulemaking"), but EPA cautions that it "interpreted CAA section 211(o)(1)(H) in the context of the facts and policy framework of the RFS2 program and based on information available at that time."[33] Most notably, EPA "reiterates that it is not determining here what emissions associated with electrolytic hydrogen constitute 'lifecycle greenhouse-gas emissions' pursuant to CAA § 211(o)(1)(H) for purposes of the RFS program."[34] If EPA disavows that it must treat induced grid emissions as "significant indirect emissions" for purposes of the RFS program, then Treasury cannot consider induced grid emissions because Treasury must apply the "same meaning" of that term "given" under § 211(o)(1)(H).[35] And because EPA to this day disavows considering induced grid emissions in the RFS context, Treasury's consideration of induced grid emissions certainly does not reflect EPA's interpretation of § 211(o)(1)(H) "in effect on the date of enactment of this section," as § 45V requires.[36]

This problem is further compounded by EPA's repeated disclaimers that it has not conducted a lifecycle analysis in the hydrogen context.[37] EPA does not say that it considers induced grid emissions in the clean hydrogen context or that such consideration is compelled by *EPA*'s interpretation of § 211(o)(1)(H). Rather, EPA "emphasizes that it has not analyzed the lifecycle greenhouse-gas emissions associated with or conducted a lifecycle analysis for electrolytic hydrogen production" and concedes that it has not "interpreted CAA 211(o)(1)(H) in the context of hydrogen production."[38] Once all these limitations and qualifications are accounted for, EPA claims with respect to this particular rulemaking merely that it "believes it *would be* reasonable and consistent with the agency's precedent *for Treasury* to determine that induced grid emissions are an anticipated real-world result of electrolytic hydrogen production that must be

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32 *Id.*

33 Letter from Janet G. McCabe, Deputy Administrator, EPA, to Honorable Lily Batchelder, Assistant Secretary for Tax Policy, Dep't of Treasury, at 2 (Dec. 20, 2023), https://home.treasury.gov/system/files/136/45V-NPRM-EPA-letter.pdf.

34 *Id*. at 4.

35 26 U.S.C. § 45V(c)(1)(A); 42 U.S.C. § 7545(o)(1)(H).

36 26 U.S.C. § 45V(c)(1)(A).

37 In its final 2023 renewable fuels standard rule, EPA acknowledged that incentives for "clean hydrogen production[] and other areas have effectively shifted the policy ground," but did not complete a lifecycle analysis for hydrogen. Env't Prot. Agency, Final Rule, Renewable Fuel Standard (RFS) Program: Standards for 2023–2025 and Other Changes, 88 Fed. Reg. 44,468, 44,473, 44,501 (July 12, 2023).

38 EPA Letter at 2.

considered in lifecycle greenhouse-gas analyses under IRC section 45V."[39] That is not good enough to satisfy Treasury's statutory obligation in § 45V to apply the "same meaning *given*" to "lifecycle greenhouse gas emissions" in § 211(o)(1)(H).[40]

Third, EPA's limited analysis as to why induced grid emissions could count as "significant indirect emissions" is meritless and cannot serve as the basis for Treasury's assertion of authority. That analysis consists entirely of inferential leaps drawn from the RFS2 rulemaking. That rulemaking considered whether greenhouse-gas emissions from international indirect land use changes caused by biofuel production were "significant indirect emissions" under § 211(o)(1)(H). EPA concluded that they were.[41] But that conclusion shows only that EPA has followed the one textual requirement of § 211(o)(1)(H), which explicitly refers to "significant indirect emissions *such as significant emissions from land use changes*."[42] The fact that EPA considered the one "significant indirect emission" actually enumerated in § 211(o)(1)(H) does not provide any indication as to whether other indirect emissions, like induced grid emissions, may or should be considered.

That is especially true given that the EPA Letter concedes that it ultimately *declined* to account for induced grid emissions in the RFS2 rulemaking: "In the RFS2 rulemaking the EPA discussed induced grid emissions associated with biofuel production generally and indicated that such emissions may be significant indirect emissions. However, the agency concluded that the analytical tools available at the time were not sufficient to include induced grid emissions in [life-cycle assessments]."[43] Treasury's reliance on a crude, categorical heuristic in the proposed rule stands in stark contrast to the detailed and sophisticated analysis EPA performs when assessing indirect emissions from a project in administering its own renewable fuel program.[44] EPA has never applied a general assumption in the RFS program that using existing power resources necessarily produces induced emissions and that using new power resources does not. Moreover,

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39 *Id.* (emphasis added); *see also id.* at 4 ("It would be *reasonable* for Treasury to include induced grid emissions under IRC section 45V."

40 26 U.S.C. § 45V(c)(1)(A).

41 EPA Letter at 2-3 (citing 75 Fed. Reg. 14670, 14765-67 (Mar. 26, 2010)).

42 42 U.S.C. § 7545(o)(1)(H) (emphasis added).

43 EPA Letter at 4.

44 *See* NEI et al. Comment to Treasury, Notice 2022-49, at 10-13 (May 24, 2023) (describing the careful analysis EPA uses to apply the definition of "lifecycle greenhouse gas emissions" for various types of renewable fuels and noting that EPA "has not treated new electric generation resources any differently than existing ones"); *see also, e.g.*, Support for Classification of Biofuel Produced from Waste Derived Biogas as Cellulosic Biofuel and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuel Produced from Waste Derived Biogas, EPA Air and Radiation Docket EPA-HQ-OAR-2012-0401, at 22 (July 1, 2014), https://www.regulations.gov/document/EPA-HQ-OAR-2012-0401-0243 (rejecting distinction between landfills that had existing gas-to-electricity projects and those that were newly-installing those projects); *Green Plains Superior, LLC Fuel Pathway Determination under the RFS Program*, at 9 (Feb. 14, 2023), https://www.epa.gov/system/files/documents/2023-02/grn-plains-superior-determin-ltr-2023-02-14-signed.pdf (failing to consider induced grid emissions in a recent adjudication under RFS when determining the emissions associated with electricity used as an energy input to fuel production).

Congress directed Treasury as to how it should account for emissions: using the GREET model, which, as discussed below, does not consider induced emissions.

There are other problems as well with EPA's substantive analysis. The EPA Letter cites EPA's voluntary "Green Power Partnership" program for renewables as an example where EPA previously favored "power sourced from newer capacity."[45] But that program has a lengthy lookback and allows older facilities to "qualify as a 'new' facility" if specified conditions are met, including if the "facility has been re-powered on or after the 15-year new date such that 80 percent of the fair market value of the project stems from new generation equipment installed as part of the re-powering."[46] Thus, EPA's own examples do not support the categorical distinction between new and existing resources found in the proposed regulations, but rather a more nuanced approach along the lines of the alternatives suggested in Part V below.

Fourth, in explaining why consideration of induced grid emissions could make sense in the context of clean hydrogen production, EPA (and by incorporation, Treasury) relies almost entirely on conclusory statements without any acknowledgment of the complexity of the question. The EPA Letter strings together several contestable propositions, usually without any support, to reach that result.[47] For example, the Letter asserts 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,'" and that "Treasury could reasonably determine that induced grid emissions are 'significant,'" but only if "[*a*]*ssuming* that electrolytic hydrogen production is not expected to entail large greenhouse-gas emissions from sources or activities other than electricity use."[48] Positing what "would be" a reasonable interpretation in a different context that EPA has not studied based on unsupported "appearances" and "assumptions" cannot turn a statutory cross-reference in § 45V into a mandate to impose an incrementality requirement.

Finally, the EPA Letter at best provides support only for the conclusion that EPA generally takes a "consequential" or "real-world" approach to indirect emissions.[49] But if that is all that the cross-reference to § 211(o)(1)(H) means, then Treasury cannot impose the categorical incrementality requirement it has proposed rather than a more fine-grained analysis that accounts for actual market conditions, as discussed further below in Part IV.A.2.

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45 EPA Letter at 6.

46 EPA, *EPA's Green Power Partnership: Partnership Requirements*, at 9 (May 2019), https://www.epa.gov/sites/default/files/2016-01/documents/gpp_partnership_reqs.pdf.

47 *See, e.g.*, EPA Letter at 4-5 (asserting that "[e]lectricity users, including hydrogen producers, can cause or induce emissions by adding new load and consuming electricity," and further asserting that "[b]ecause the grid must always balance electricity demand with supply, this increased electricity demand results in increased electricity supply and, if the new electricity is not zero-emitting, additional emissions from the grid").

48 *Id.* at 5.

49 *Id.* at 3-4.

<u>(3) "Most Recent GREET Model."</u> The definitional provision regarding the GREET model provides another clear statutory barrier to an incrementality requirement.[50] That provision requires Treasury to use "emissions through the point of production (well-to-gate), *as determined* under the most recent [GREET model]… developed by Argonne National Laboratory, or a successor model (as determined by the Secretary)."[51] As noted above, this provision imposes important limitations on the incorporation of § 211(o)(1)(H), including by specifying that only "emissions through the point of production" are to be considered, and by significantly cabining the discretion of Treasury to make its own determinations of significant indirect emissions, in contrast to the full § 211(o)(1)(H) provision, which provides EPA with discretion "as determined by the Administrator" in conducting its own lifecycle GHG emissions analysis. Congress explicitly named the GREET model for its quantitative rigorous analysis and in light of Treasury's lack of expertise in emissions modeling and the power sector.

In addition, it specifies that emissions are to be considered "as determined under the most recent" GREET model.[52] An incrementality requirement is inconsistent with the GREET model, which with respect to hydrogen production has not changed in any material way since the IRA was enacted.[53] That model does not distinguish between sources of electricity based on whether they are existing or new, and the model still includes drop-down boxes to display pre-programmed emissions results for electrolyzers receiving electricity directly from a nuclear power plant.

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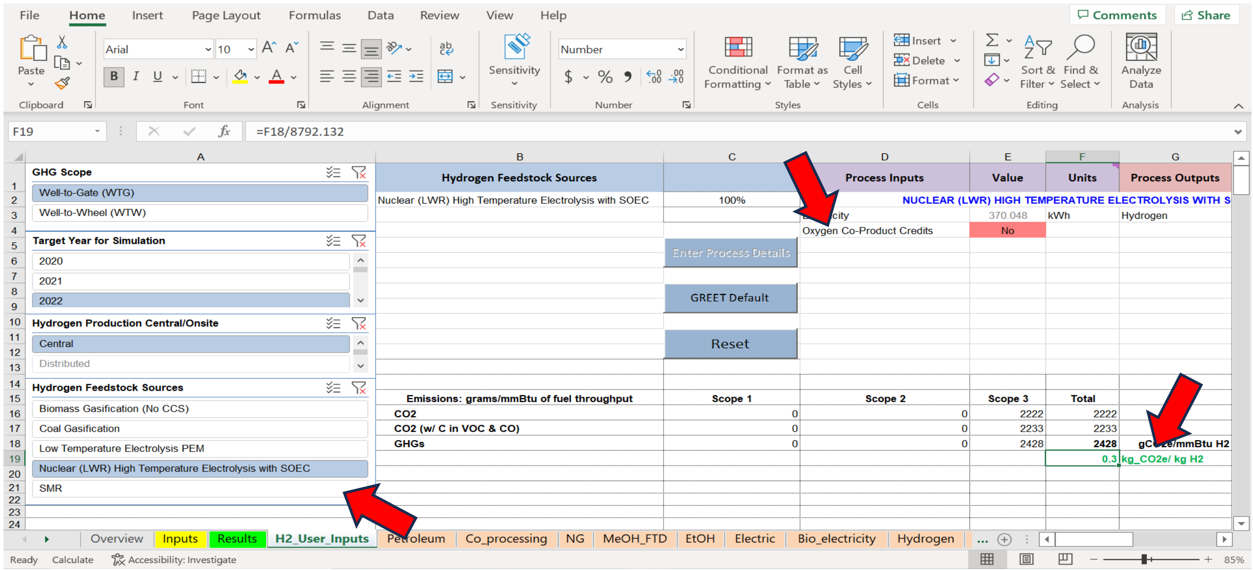
[50] 26 U.S.C. § 45V(c)(1)(B).

[51] *Id.* (emphasis added).

[52] *Id.* By contrast, § 211(o)(1)(H) confers discretion on the EPA Administrator to make such determinations. *Cf.* 42 U.S.C. § 7545(o)(1)(H) (providing that the "aggregate quantity of greenhouse gas emissions" are to be "determined by the Administrator").

[53] *See, e.g.*, Amgad Elgowainy et al., *Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production*, Argonne Nat'l Lab'y, at 2 (Oct. 2022), https://greet.es.anl.gov/files/hydrogenreport2022 (affirming that the GREET model's inputs include the emissions only of the direct source of electricity for production).



Thus, under the GREET model—both now and as it existed when § 45V was enacted—there is no ambiguity as to the emissions profile of a behind-the-meter electrolyzer that only receives electricity generated by a nuclear power plant. Indeed, initially, NRDC accepted that under that GREET model, "[p]roducers of electrolytic hydrogen that use primarily on-site, zero-carbon electricity should immediately qualify."[54] In a webinar on "GREET Model for Hydrogen Life Cycle Emissions" that DOE hosted in June 2022 shortly before the passage of the IRA, ANL recognized that well-to-gate GHG emissions from nuclear-based hydrogen production were minimal.[55] And CATF/NRDC later acknowledged that the "current version of the GREET model … ignores systemwide grid emission related to hydrogen production."[56] Nor does the GREET model distinguish between environmental attribute credits ("EACs") sourced from new versus existing resources.

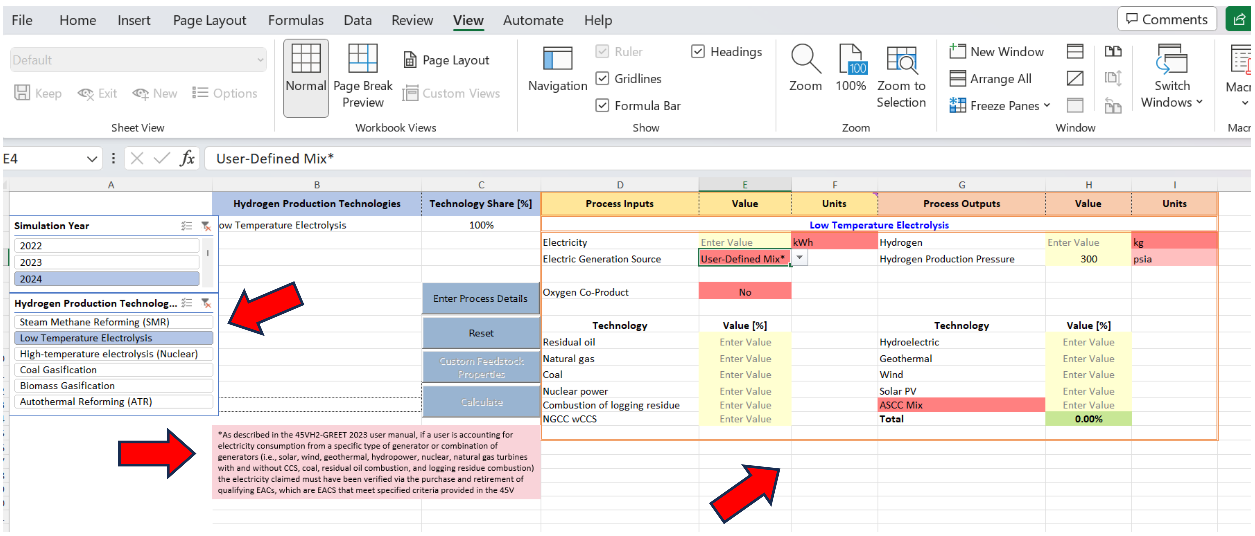
However, DOE has now created, and the proposed regulations adopt, a new set of instructions specific to the § 45V context ("45VH2-GREET2023"). Though the underlying model remains the same, DOE's instructions now direct the user to select "User Defined Mix" for the emissions factor, even for behind-the-meter hydrogen production, unless the electricity source

54 NRDC December Comment at 2; *see also* Princeton ZERO Lab Dec. 2023 comments at 1 ("[T]he most important factor in GREET's lifecycle emissions calculation is the embodied emissions rate of the input electricity. This rate depends on the ultimate source of the generation, which is easy to determine for hydrogen produced using directly connected, behind-the-meter clean resources . . . .").

55 Amgad Elgowainy, Argonne Nat'l Lab'y, Presentation at H2IQ webinar: *GREET Model for Hydrogen Life Cycle Emissions*, at Slide 8 (June 15, 2022), https://www.energy.gov/sites/default/files/2022-06/hfto-june-h2iqhour-2022-argonne.pdf.

56 CATF/NRDC April Comment Letter at 4.

meets the proposed rule's incrementality requirement.[57] The existing GREET model does indeed let a user opt not to use the pre-programmed nuclear-based emissions results shown above and, instead, manually input data regarding the electricity mix being used by a hydrogen project. Following the example of a behind-the-meter electrolyzer, that would be an electricity mix of 100 percent nuclear, since the electrolyzer has no way to receive power from the grid, and the emissions results remain the same (0.3 kg CO2e / kg H2). The DOE instructions seek to prohibit hydrogen producers from using this existing functionality of the existing GREET model. This is made clear in the screenshot below:



The new user manual (referenced in the pink box in the image above) was not issued by Argonne National Laboratory, is not part of the GREET model itself, and is inconsistent with the pre-programmed results and underlying functionality of that model.[58] Nonetheless, the proposed regulations assert that 45VH2-GREET2023 is the "most recent" version of the GREET model. Specifically, proposed regulation § 1.45V-1(a)(8)(ii) provides that the term "most recent GREET model" means "the latest version of 45VH2-GREET developed by [ANL] that is publicly available on the first day of the taxpayer's taxable year in which the qualified clean hydrogen for which the taxpayer is claiming the section 45V credit was produced."[59]

Developing a new set of user instructions that apply only in the specific context of § 45V and that direct the user to disregard the GREET model's nuclear-specific emissions results can

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[57] *Compare* U.S. Dep't of Energy, *Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways Using 45VH2-GREET 2023*, at 16 (Dec. 2023) ("*DOE Guideline*") (providing emissions factor for nuclear), *with id.* at 21 (requiring that "[a]ny electricity that is not substantiated via IRS's requirements for qualifying EACs must be assumed" to have an "emissions profile that reflects the annual average emissions intensity of electricity in the NERC region that the hydrogen producer is located in").

[58] *Cf.* 26 U.S.C. § 45V(c)(1)(B) (referring to the model "developed by Argonne National Laboratory.").

[59] NPRM, 88 Fed. Reg. at 89,223. The proposed regulation also provides that "if a version of 45VH2-GREET becomes publicly available after the first day of the taxable year of production (but still within such taxable year), then the taxpayer may, in its discretion, treat such version of 45VH2-GREET as the most recent GREET model." *Id.* at 89,223-24.

hardly be considered a "successor" GREET model. The term "successor" suggests an updated version of what came before, not a bolted-on directive for use only in the § 45V context that disregards the way the model ordinarily would be applied. Indeed, ANL is expected to release its annual update to the general GREET model, which is utilized for most other applications besides § 45V eligibility. Portraying 45VH2-GREET as the "most recent" GREET model is thus not a permissible interpretation of the statutory text. The proposed rule appears to recognize this fact, and it solicits comments as to an "alternative approach" in which the Secretary determines that the "latest version of 45VH2-GREET is an appropriate 'successor model,' as provided by section 45V(c)(1)(B), for the purpose of administering the section 45V tax credit."[60] Treasury's uncertainty as to the basis of its authority confirms that it is using a gerrymandered version of the GREET model to achieve a desired outcome that the standard GREET model obviously forecloses.

Moreover, the alternative approach discussed in the proposed rule would equally violate the statute. The words "successor model" plainly refer to an updated version of GREET, not a bespoke model that diverges from GREET and is applied only in § 45V context. Moreover, as discussed above, the statute is clear that, whatever GREET model is used, it must only consider "emissions through the point of production (well-to-gate)."[61] A set of instructions that imputes a grid emissions rate to hydrogen production, even when the producer is sourcing only zero emissions power—indeed, even when the producer is located behind-the-meter and has no *access* to grid power—is manifestly inconsistent with the statute's requirements.

(4) "Any." The statutory text additionally makes clear that the clean hydrogen production tax credit should be broadly available. Thus, in setting forth the applicable percentages that govern the amount of the production tax credit at various emissions thresholds, Congress provided that the credit would apply to "*any* qualified clean hydrogen which is produced through a process that results in a lifecycle greenhouse gas emissions rate" less than the applicable threshold.[62] The Supreme Court has "repeatedly explained 'that the word 'any' has an expansive meaning',"[63] and that it means "'one or some indiscriminately of whatever kind.'"[64] Congress's choice to use this broad term makes clear that as long as the hydrogen produced falls into the category of clean hydrogen the statute identifies—namely, "qualified clean hydrogen which is produced through a

[60] *Id.* at 89,224.

[61] 26 U.S.C. § 45V(c)(1)(B).

[62] *Id.* §§ 45V(b)(2)(A)-(D)(emphasis added).

[63] *Babb v. Wilkie*, 589 U.S. 399, 405 n.2 (2020) (citation omitted).

[64] *United States v. Gonzales*, 520 U.S. 1, 5 (1997) (quoting *Webster's Third New International Dictionary*, at 97 (1976)); *see also Gallardo ex rel. Vassallo v. Marstiller*, 596 U.S. 420, 429 (2022) (reading the phrase "*any* rights . . . to payment for medical care" broadly to include "not only rights to payment for past medical expenses, but also rights to payment for future medical expenses" (citing *Gonzales*, 520 U.S. at 5); *Babb*, 589 U.S. at 405 n.2 ("We have repeatedly explained that the word 'any' has an expansive meaning." (citations omitted); *Ali v. Fed. Bureau of Prisons*, 552 U.S. 214, 218-19 (2008) (concluding that the phrase '"*any* other law enforcement officer' suggests a broad meaning"); *Harrison v. PPG Indus., Inc.*, 446 U.S. 578, 588-89 (1980) (concluding that the phrase "any other final action" used "expansive language" and thus was not limited only to final actions found in specifically enumerated sections).

process that results in a lifecycle greenhouse gas emissions rate" below the specified thresholds—it *must* be eligible for the tax credit. The agency has no discretion to subdivide that category and allow only certain hydrogen to qualify. Nor was Congress's use of the term "any" a passing accident. Congress repeated the same formulation four times—in subparagraphs (b)(2)(A), (b)(2)(B), (b)(2)(C), and (b)(2)(D)—buttressing the conclusion that Congress intended the production tax credit to be available whenever the statutory conditions were met.[65] And Congress placed the word "any" "immediately before" the phrase it modifies ("qualified clean hydrogen"), thereby "leaving no doubt that it modifies that phrase."[66]

Congress's intent therefore could not be clearer: as long as a taxpayer produces qualified clean hydrogen, it is eligible for the credit, regardless of whether that production stems from new generation adding incremental capacity to the electric grid. Treasury lacks authority to impose additional limits that directly contravene § 45V's expansive scope.

(5) Timing of § 45V Credits. Finally, the fact that Congress specified that the § 45V tax credit would be available at the start of 2023 all but confirms that an incrementality requirement could not be what Congress intended.[67] Any new resource actually available in 2023 would have been online anyway and thus could not be considered "incremental" under the offered rationale. This means Treasury has administratively created a tax credit scheme in which no one could actually earn credits when they were initially offered.[68] That result is analogous to the petitioners' argument in *King v. Burwell* that tax credits in the Affordable Care Act did not apply in states with a federal exchange, a reading that would have undermined the efficacy of the legislation.[69] There, the Court concluded that it would be "implausible that Congress meant the Act to operate in this manner."[70] So too here. The only reading of the statute consistent with the text is that existing resources can receive the tax credit immediately if they meet the specified thresholds.

This reading is confirmed by the Joint Committee on Taxation's ("JCTs") estimate of the potential impact of a bill the House of Representatives passed in April 2023 to repeal § 45V and other tax credits enacted by the IRA. JCT estimated that $127 million in clean hydrogen tax credits would be claimed in 2023.[71] If Congress intended the § 45V production tax credit to instead be

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65 *See Ali*, 552 U.S. at 220 (relying on the fact that the "word 'any' is repeated four times in the relevant portion of" the statute).

66 *Id*.

67 26 U.S.C. § 45V (statutory note).

68 While the proposed three-year lookback provision could result in some early eligibility for the tax credit, Treasury has provided no rationale for that provision, as discussed in Section IV.B below.

69 *King v. Burwell*, 576 U.S. 473, 494 (2015).

70 *Id.*

71 Joint Committee on Taxation,, JCX-7-23, *Estimated Revenue Effects of Division A, Title III of H.R. 2811, The "Limit, Save, Grow Act Of 2023," as Amended, Scheduled for Consideration by the House of Representatives on April 26, 2023*, at line 6 (Apr. 26, 2023), https://www.jct.gov/getattachment/1bd2fab7-1a0f-4c30-9a8f-94b98f3b2888/x-7-23.pdf.

available only for hydrogen projects powered by newly constructed carbon-free generation, JCT's estimate should have been zero. Incrementality is simply not required.

C. The Structure of the Statute Forecloses an Incrementality Requirement.

The plain text of § 45V alone confirms that the imposition of an incrementality requirement exceeds Treasury's authority. But that conclusion is further buttressed by examining neighboring provisions in the IRA. The statutory structure makes clear that Congress knew how to impose a vintage requirement when it wanted to do so.

An incrementality requirement is a kind of vintage requirement, and vintage requirements appear all over the statute. "When Congress includes particular language in one section of a statute but omits it from a neighbor, we normally understand that difference in language to convey a difference in meaning."[72] Section 45V itself contains at least two vintage requirements: § 45V(c)(3)(C) provides that a "qualified clean hydrogen production facility" is one that begins construction before 2033,[73] and § 45V(e)(2)(A) limits when hydrogen production facilities can receive increased credit amounts due to compliance with certain prevailing wage and apprenticeship requirements.[74] Similar requirements also exist elsewhere in the IRA. For example, a "qualified nuclear power facility" is defined in § 45U as one that is "placed in service before the date of the enactment of this section."[75] And the "domestic content bonus credit amount" in § 45Y specifies certain percentages linked to specific time periods.[76] And more broadly still, the IRA creates tax credits for new carbon-free electric generators, including new nuclear plants.[77] Given Congress's deliberate inclusion of vintage requirements where it saw fit to include them, it is clear that Congress did not intend for any such restriction to apply to the § 45V tax credit, and Treasury cannot now administratively impose a vintage requirement beyond what Congress has specified.

Additionally, § 45V must be interpreted in light of Congress's initiative in the Infrastructure Investment and Jobs Act ("IIJA") to create "clean hydrogen hubs" eligible for $8 billion in funding. There, Congress specified that the "clean hydrogen hubs" selected by the Department of Energy should include at least one hub that "shall demonstrate the production of clean hydrogen from nuclear energy."[78] The § 45V tax credit provides additional financial support for hub recipients—yet the proposed rule would allow such additional support only for some hub

[72] *Bittner v. United States*, 598 U.S. 85, 94 (2023).

[73] 26 U.S.C. § 45V(c)(3)(C).

[74] *Id.* § 45V(e)(2)(A) (referring to facilities "the construction of which begins prior to the date that is 60 days after the Secretary publishes guidance with respect to" the prevailing wage and apprenticeship requirements).

[75] *Id.* § 45U(b)(1)(C).

[76] *Id.* § 45Y(g)(11)(C)(i).

[77] *See id.* § 45Y(b)(1)(A).

[78] 42 U.S.C. § 16161a(c)(3)(A)(iii).

participants and not for others. Rather than creating tension between these two statutes, the better interpretation is to read them as mutually reinforcing and interpret them in parallel.

D. The Major Questions Doctrine Forecloses an Incrementality Requirement.

For the reasons stated above, the text and structure of the statute do not permit Treasury to impose an incrementality requirement. But, if there were any remaining doubt, the major questions doctrine definitively forecloses Treasury from doing so. Even if the statute could somehow be read to permit an incrementality requirement, inferring such authority runs headlong into the major questions doctrine: Treasury and the IRS seek to use a tax subsidy to fundamentally reshape an area of "vast economic and political significance" based on their own non-expert predictions about how a dynamic power sector will respond to new demand created by hydrogen production.[79]

To begin, it is undisputed that § 45V does not explicitly contain an incrementality requirement. The notice of proposed rulemaking does not claim that the statute unambiguously authorizes this requirement, and even supporters of the requirement concede that at best it can be deduced from dubious inferences and nuanced cross-references in the text. For instance, CATF/NRDC argue that the incrementality requirement "*inheres* within section 45V's emission thresholds and its incorporation of section 211(o) of the Clean Air Act."[80] This is not an adequate basis for the IRS to assert broad authority to shape the emerging clean hydrogen industry based on predictions about how grid operators and other power suppliers and consumers will respond to new demand.

Nor can it be disputed that an incrementality requirement bears on a question of vast political and economic significance. As discussed above, it would be one thing for the IRS to focus on intricacies of the production process at the hydrogen plant itself in determining eligibility for the production tax credit—a task that already stretches the limits of the IRS's expertise. But it is another thing entirely for the IRS to task itself with examining the purported indirect impacts of clean hydrogen production on the emissions profile of all other grid users. That assertion of authority over not only individual hydrogen producers but also the makeup of the rest of the electric grid and broader systemwide emissions attributable to others besides hydrogen producers goes far beyond IRS's competence.[81] Particularly given the numerous provisions in the IRA that already directly provide incentives for new renewables and other clean energy resources,[82] it is not plausible that Congress intended for the IRS to use a narrow provision regarding tax credits for hydrogen production to indirectly regulate the mix of resources serving the power grid more broadly.[83]

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[79] *Utility Air Reg. Grp. v. EPA*, 573 U.S. 302, 324 (2014).

[80] CATF/NRDC April Comment Letter at 12.

[81] *Cf. West Virginia v. EPA*, 597 U.S. 697, 724 (2022).

[82] *See, e.g.*, 26 U.S.C. §§ 45Y, 48E.

[83] This inference is especially implausible given that Congress considered—and decided against—regulating the overall mix of the electric grid. Early versions of the IRA included a Clean Electricity Performance Program that

The Supreme Court "typically greet[s]" such assertions of "extravagant statutory power over the national economy" with "skepticism,"[84] and requires "something more than a merely plausible textual basis for the agency action is necessary."[85] Thus, the IRS may promulgate an incrementality requirement only if it can "point to 'clear congressional authorization' for the power it claims."[86] Here, the IRS has not even clearly identified the statutory basis for imposing an incrementality requirement, and it is unlikely that this authority, which EPA itself has never asserted under the CAA, would be tucked into a qualified cross-reference to that statute in § 45V.[87]

Similar to the Supreme Court's recent cases applying the major questions doctrine,[88] this proposed rule involves a non-expert agency (the IRS) setting policy in unprecedented fashion in an area beyond its expertise. The Court has recognized that "[w]hen an agency has no comparative expertise in making certain policy judgments . . . Congress presumably would not task it with doing so."[89] The Supreme Court has already applied this principle to the IRS itself: in *King v. Burwell*, the Court concluded that it was "especially unlikely that Congress would have delegated this decision to the *IRS*, which has no expertise in crafting health insurance policy of this sort."[90] And the Court has reiterated that federal agencies cannot rely on cryptic statutory provisions to assert authority beyond their expertise. For example, in *Alabama Association of Realtors v. Department of Health and Human Services*, the Court held that the Centers for Disease Control could not rely on its authority to adopt measures "necessary to prevent the . . . spread of" disease to set national housing policy during the COVID-19 pandemic—a subject plainly beyond its competence.[91] And the Court rejected the Occupational Safety and Health Administration's vaccine-or-test mandate on the ground that the agency's organic statute empowered the Secretary

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would have done what Treasury seeks to do with the incrementality requirement—increase the amount of clean energy distributed to those using electric grid beyond what would otherwise happen via other incentives. *See, e.g.*, H.R. Rep. No. 117-130(II), at 1661-66 (2021) (Title III, Subtitle D, § 30411). Congress's rejection of these legislative proposals further supports the application of the major questions doctrine here. *See, e.g.*, *West Virginia*, 597 U.S. at 731 (noting that the Court "cannot ignore that the regulatory writ EPA newly uncovered conveniently enabled it to enact a program that . . . Congress considered and rejected multiple times" (citation and internal quotation marks omitted)).

84 *Utility Air*, 573 U.S. at 324.

85 *West Virginia*, 597 U.S. at 723 (quoting *Utility Air*, 573 U.S. at 324).

86 *Id*.

87 *See e.g.*, *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001); *Burwell*, 576 U.S. at 497 (doubting that "Congress made the viability of the entire Affordable Care Act turn on the ultimate ancillary provision: a sub-sub-sub section of the Tax Code"); *see also Brown & Williamson*, 529 U.S. at 160 (noting that Congress "could not have intended to delegate" such sweeping authority "in so cryptic a fashion.").

88 *See, e.g.*, *Biden v. Nebraska*, 600 U.S. 477 (2023); *West Virginia*, 597 U.S. 697; *Nat'l Fed'n of Indep. Bus. v. Dep't of Lab.(NFIB)*, 595 U.S. 109 (2022).

89 *West Virginia*, 597 U.S. at 729 (alterations, citation, and internal quotation marks omitted).

90 *Burwell*, 576 U.S. at 486 (emphasis in original).

91 141 S. Ct. 2485, 2487 (2021) (per curiam).

only "to set *workplace* safety standards, not broad public health measures."[92] As the Court explained, "no provision of the [OSH] Act addresses public health more generally, which falls outside of OSHA's sphere of expertise."[93]

These precedents straightforwardly preclude the IRS from using its narrow authority to determine eligibility for a tax credit to set national energy policy with respect to the emerging clean hydrogen sector. The IRS has no expertise in power system modeling. Nor does the statute even require Treasury to consult with other agencies which do have expertise in that subject to determine who qualifies for the § 45V tax credit. Given this statutory scheme, Congress could not have intended for the IRS's administration of § 45V to center eligibility for the tax credit on ancillary questions of incrementality.

III. An Incrementality Requirement Will Frustrate Congress's Intent and Crush the Nascent Hydrogen Industry.

The proposed incrementality requirement is also fundamentally inconsistent with the purpose of § 45V and other clean hydrogen legislation.[94] Congress's primary purpose in enacting § 45V was to accelerate the development of the clean hydrogen industry, recognizing that a robust clean hydrogen supply is necessary for the nation to meet its decarbonization goals. The sectors of the economy that will use clean hydrogen are hard to electrify, and if clean hydrogen is unavailable, they will continue to emit large quantities of carbon dioxide. Thus, Congress decided to invest significantly in clean hydrogen production—and nowhere in the statute did it authorize Treasury to withhold the tax credit based on the potential for near-term increases in grid emissions. Yet the proposed rule myopically focuses on the latter and ignores entirely the impact of an incrementality requirement on the long-term trajectory for clean hydrogen production and the concomitant reduction in carbon emissions for industries with no other means to decarbonize. Treasury must not adopt a final rule that countermands congressional intent; nor can it adopt a final rule that entirely ignores the primary problem that Congress sought to solve.

A. Congress Enacted § 45V to Support the Development of a National Hydrogen Industry.

There can be no dispute that Congress enacted § 45V for the purpose of supporting the nascent clean hydrogen industry through tax credits, which in turn will help decarbonize difficult-to-decarbonize sectors of the economy. For example, in announcing the proposed regulations, the White House issued a statement explaining that the IRA and the Bipartisan Infrastructure Law "feature the world's most ambitious policies to support the growth of our nation's clean hydrogen

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92 *NFIB*, 595 U.S. at 117.

93 *Id.* at 118.

94 *Cf.* 26 U.S.C. § 45V(f) (authorizing the Secretary of the Treasury to promulgate regulations "to carry out the purposes of [§ 45V], including regulations or other guidance for determining lifecycle greenhouse gas emissions").

industry."[95] The statement also noted that the new regulations "represent[] a major step forward in ... driving the growth of an emerging industry, and positioning the United States as a leader in one of the key energy technologies of the future."[96]

Moreover, § 45V is only one component of Congress's ongoing efforts to promote hydrogen development. In the 2021 IIJA, Congress found that hydrogen (1) "plays a critical part in the comprehensive energy portfolio of the United States," (2) can "provide[] economic value and environmental benefits for diverse applications across multiple sectors of the economy," and (3) "can be produced from a variety of domestically available clean energy sources…."[97] Specifically, Congress established a clean hydrogen research and development program and directed the Department of Energy to "develop a technologically and economically feasible national strategy and roadmap to facilitate widescale production, processing, delivery, storage, and use of clean hydrogen."[98] Congress also authorized $8 billion in investment in "hydrogen hubs," requiring that at least one of these regional hubs demonstrate the production of clean hydrogen from nuclear energy.[99]

The administration has acknowledged that § 45V complements and advances Congress's unified clean hydrogen agenda. In its statement announcing the proposed rule, the White House recognized that the "§ 45V tax credit provides a tax credit of up to $3 per kilogram of hydrogen to projects with low lifecycle greenhouse gas emissions, and accompanies other hydrogen programs such as the Department of Energy's Regional Clean Hydrogen Hubs Program."[100]

Congressional support for hydrogen accords with the body of research on mitigating climate change, which confirms that hydrogen is essential to decarbonizing certain industries. Unlike industries that can simply turn to electricity as a new fuel source, certain industries—including chemical manufacturing, steelmaking, industrial heat, and heavy-duty transportation—are not candidates for electrification.[101] Among other reasons, these industries rely on high-heat industrial processes that electricity cannot serve, or in the case of heavy-duty transportation, are constrained by the practicalities of electric delivery. Substituting hydrogen for existing fuels can result in significant carbon reductions. For example, using hydrogen in the steel refining process

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[95] The White House, *Treasury Sets Out Proposed Rules for Transformative Clean Hydrogen Incentives* (Dec. 22, 2023), https://www.whitehouse.gov/cleanenergy/clean-energy-updates/2023/12/22/treasury-sets-out-proposed-rules-for-transformative-clean-hydrogen-incentives (White House Statement).

[96] White House Statement.

[97] Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 1005-06, § 40311(a) (2021).

[98] *E.g.*, 42 U.S.C. § 16154(j); 42 U.S.C. § 16161b(a)(1).

[99] 42 U.S.C. § 16161a(c)(3)(A)(iii) and (d).

[100] White House Statement; *see also* Pathways Report at 1 (noting that the National Clean Hydrogen Strategy and Roadmap identify "economic opportunities for the production, processing, transport, storage, and use of clean hydrogen that exist for merchant nuclear power plants operating in deregulated markets").

[101] U.S. Dep't of Energy, *U.S. National Clean Hydrogen Strategy and Roadmap*, at 29-34 (June 2023) ("Hydrogen Strategy and Roadmap"), https://www.hydrogen.energy.gov/library/roadmaps-vision/clean-hydrogen-strategy-roadmap.

rather than coke or natural gas can reduce the lifecycle emissions of steelmaking by 40-70 percent.[102]

B. Achieving Hydrogen's Decarbonization Promise Requires an Immediate Kickstart.

As mandated by the IIJA, DOE prepared a long-term strategy for establishing a hydrogen economy, and pathways to meeting its goals. One of the key takeaways of these reports is that to leverage hydrogen as a decarbonizing force over the long term, it is essential *now* to scale production and encourage demand-side investment.[103] Without taking immediate action, hydrogen may not be economic after the production tax credit expires in the 2040s.[104] To achieve this, DOE proposed a three-stage pathway to bring hydrogen production commercial scale:

2023-2026: Near-term expansion where clean hydrogen replaces the most carbon-intensive activities;

2027-2034: New infrastructure is built out to reduce the total cost of hydrogen and improve the business case for end-use applications; and

2035+: Self-sustaining commercial hydrogen develops prior to the termination of the production tax credit.[105]

To realize these goals requires evolution both on the demand and supply side. On the supply side, clean hydrogen must increase from near-zero today to 10 million metric tons by 2030, then double to 20 million metric tons by 2040, and increase to 50 million metric tons by 2050.[106] DOE stresses that meeting this goal will "be driven by falling production costs dependent on" "[t]he availability of low-cost, clean electricity."[107] Notably, the Department of Energy has repeatedly indicated that accomplishing these goals will require "[d]eploy[ing] *clean* hydrogen from … nuclear…."[108]

C. Treasury's Incrementality Requirement Will Undermine the National Hydrogen Strategy.

The proposed rule purports to impose an incrementality requirement to reduce near-term carbon emissions in the power generator sector—a sector that is already decarbonizing and has

[102] *Id.* at 30.

[103] Pathways Report at 2.

[104] *Id.*

[105] Hydrogen Strategy and Roadmap at 31.

[106] *Id.* at 6, 68.

[107] *Id.*

[108] Hydrogen Strategy and Roadmap at 69; *see also id.* at 6 ("Hydrogen is also seen as an enabling technology—enabling renewables through long-duration energy storage and offering flexibility and multiple revenue streams to clean power generation such as today's nuclear fleet as well as advanced nuclear and other innovative technologies."); *id.* at 14 ("Clean hydrogen can be produced through various pathways, including water-splitting using renewable or nuclear power").

existing pathways and numerous subsidies to do so[109]—without even considering the adverse effects on hydrogen-based decarbonization efforts. The incrementality requirement is a classic example of agency tunnel vision.[110] The proposed rule is so narrowly focused on trying to prevent any near-term carbon emissions from activities unrelated to hydrogen that it loses sight of the larger picture: namely, Congress's recognition, supported by DOE's analysis, that successful decarbonization of other sectors will require a robust hydrogen industry. The proposed rule offers no cost-benefit analysis justifying its focus on near-term emissions within the power system over a more successful ramp-up of a clean hydrogen industry that will provide significant mid- and long-term emissions avoidance across other sectors of the economy. Indeed, it does not even consider that latter aspect of the problem at all. That is a paradigmatic example of arbitrary and capricious agency decision-making.[111]

In fact, here there is good reason to believe that an incrementality requirement will significantly slow clean hydrogen production. Electrolyzers are expensive: units cost between \$700 and \$800/kW, excluding installation, and all in costs exceed \$2,000/kW.[112] To be economic, producers must operate 24/7 at the maximum output level. New renewable entrants, however, typically are not capable of supporting 24-hour operation. Solar naturally cannot furnish EACs during at least half of the day on average, and wind resources are unpredictable. Although storage is becoming increasingly common, pairing storage with wind or solar adds yet more expense. EACs for hybrid resources may be prohibitively expensive to obtain in view of their flexibility.

To illustrate the cost burden imposed by an incrementality requirement, consider the situation faced by hydrogen producers in the PJM region. Within PJM, EACs from new renewable generators are in high demand due to state renewable portfolio standards and are currently priced at about \$34/MWh,[113] which translates to about \$1.7/kg of hydrogen.[114] Because the pre-tax value of the § 45V credit itself is about \$3.8/kg initially, the incrementality requirement *alone* would eat about 45 percent of the tax credit. Such a significant reduction in the value of the tax credit would

[109] *See, e.g.*, Cong. Rsch. Serv., R47385, *U.S. Greenhouse Gas Emissions Trends and Projections from the Inflation Reduction Act*, at 3, Fig. 1 (Jan. 12, 2023); U.S. Energy Info. Admin., *Federal Financial Interventions and Subsidies in Energy in Fiscal Years 2016–2022*, at 7 (Aug. 2023), https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf; Goldman Sachs, The US is Poised for an Energy Revolution (Apr. 17, 2023), https://www.goldmansachs.com/intelligence/pages/the-us-is-poised-for-an-energy-revolution.html.

[110] Stephen G. Breyer, *Breaking the Vicious Circle: Toward Effective Risk Regulation* (1993).

[111] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("[A]n agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider[or] entirely failed to consider an important aspect of the problem…").

[112] These figures are based on submissions to DOE as part of the Hydrogen Hub application process.

[113] Platt's Megawatt Daily, at 11 (Feb 2, 2024) (referencing \$33.75/MWh price for PJM Tri-Qualified Renewable Energy Credit).

[114] Assuming a typical electrolyzer efficiency of 0.05 megawatt hours per 1 kilogram of hydrogen produced.

erode the growth of clean electrolytic hydrogen production and frustrate the stated goal of jump-starting a vibrant clean hydrogen industry.

Relatedly, the incrementality requirement would devastate Congress's $8 billion initiative in the IIJA to support the development of hydrogen hubs. These hydrogen hubs, which DOE "expects … will be capable of producing impactful, commercial-scale quantities of clean hydrogen at a rate of at least 50-100 metric tons (MT) per day," are to enter commercial operation as soon as 2028,[115] "achieving nearly one third of the 2030 U.S. clean hydrogen production goal."[116] DOE indicated that hub applicants could "use a mix of generation assets and balance their availability with the electric grid;"[117] it did not limit electricity sources to new renewable units. Hydrogen hubs are essential to the nation's broader hydrogen strategy because they will "drive scale in production, distribution, and storage to facilitate market liftoff."[118]

In enacting the IIJA and § 45V, Congress sought to kickstart the hydrogen industry by supporting both up-front capital costs in the IIJA and ongoing operating costs through § 45V. At this early stage, both types of support are essential to making the business case for hydrogen production and encouraging prospective entrants to move forward. By restricting § 45V credits to a small pool of EACs that may be prohibitively expensive, Treasury risks the entire economic proposition of early entry.

Treasury should also not ignore that Congress and sister agencies have supported initiatives that may lead to some short-term "induced emissions" but yield even greater long-term decarbonization benefits. For example, in the electric vehicle tax credit in Internal Revenue Code § 30D, Congress chose to support electric vehicles because of their long-term importance to decarbonization, even though in the short term they will add electricity demand to the grid, which may result in increased power sector emissions. And in a proposed rule to set vehicle emissions standards for the 2027-2032 model years, EPA decided to continue measuring emissions from a vehicle's tailpipe, which resulted in 0/g mile emissions factor for electric vehicles.[119] Addressing

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[115] U.S. Dep't of Energy, *Funding Opportunity Announcement (FOA) Number: DE-FOA-0002779*, at 14 (Sept. 22, 2022), https://www.energy.gov/oced/funding-notice-regional-clean-hydrogen-hubs ("DOE, *Funding Opportunity Announcement*").

[116] The White House, *Biden-Harris Administration Announces Regional Clean Hydrogen Hubs to Drive Clean Manufacturing and Jobs* (Oct. 13, 2023), https://www.whitehouse.gov/briefing-room/statements-releases/2023/10/13/biden-harris-administration-announces-regional-clean-hydrogen-hubs-to-drive-clean-manufacturing-and-jobs/.

[117] DOE, *Funding Opportunity Announcement* at 43.

[118] Hydrogen Strategy and Roadmap at 2; Pathways Report at 2 (Hydrogen hubs "will advance new networks of shared hydrogen infrastructure.").

[119] Env't Prot. Agency, Proposed Rules, Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light Duty and Medium-Duty Vehicles, 88 Fed. Reg. 29,184, 29,252 (May 5, 2023).

grid emissions in particular, EPA noted that it had previously extended the 0/g mile provision "because power sector emissions were declining," and found that the same is true now.[120]

In a statement issued shortly after the proposed rule was announced, Senator Joe Manchin stated that the rule would "only make it more difficult to jumpstart the hydrogen market" and "kneecap the hydrogen market before it can even begin." Likewise, Senator Tom Carper—the primary author of § 45V—has stated that Congress "intended for the clean hydrogen incentives to be flexible and technology-neutral." The proposed rule, by contrast, "does not fully reflect this intent, potentially jeopardizing the clean hydrogen industry's ability to get off the ground successfully." These Senators are right. In finalizing the rule, Treasury must consider the consequences of an incrementality requirement for hydrogen production and for the carbon emissions that a robust clean hydrogen industry will avoid.

Some supporters of an incrementality requirement have pointed to a colloquy on the Senate floor between Senators Carper and Wyden to contend that Congress did not wish to allow any short-term increase in emissions. In that colloquy, the Senators state that "in determining 'lifecycle greenhouse gas emissions,'" the Treasury Department "shall recognize and incorporate indirect book accounting factors" that "reduce effective greenhouse gas emissions," such as "renewable energy credits, renewable thermal credits, renewable identification numbers, or biogas credits."[121] This quote provides no support for an incrementality requirement. The text of the statute does not authorize Treasury to curtail the tax credit to avoid any possible short-term, incidental increase in grid emissions ultimately attributable to generation supplying other electricity users. And the legislative history merely notes that EACs are a useful tool for reducing carbon emissions. No one disputes that.

Last, Treasury must acknowledge that the proposed incrementality requirement would leave the United States at a competitive disadvantage relative to other countries. European and Asian nations have embraced nuclear to drive innovation in hydrogen production, including France's recent announcement to include nuclear in $4 billion of clean hydrogen subsidies.[122]

In sum, Treasury's proposed incrementality requirement is at cross-purposes with Congress's goals in enacting § 45V. An incrementality requirement will leave clean hydrogen producers unable to rely upon nuclear plants to power their electrolyzers if they wish to receive the tax credit—directly contrary to DOE's assessment that nuclear plants are needed to create clean

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[120] *Id.*; *see also id.* ("As noted elsewhere, power sector emissions are expected to decline further in the future. EPA continues to believe that it is appropriate for any vehicle which has zero tailpipe emissions to use 0 g/mi as its compliance value.").

[121] 168 Cong. Rec. S4165-66 (daily ed. Aug. 6, 2022).

[122] Francois De Beaupuy, *France Earmarks €4 Billion to Support Low-Carbon Hydrogen Output*, Bloomberg (Aug. 31, 2023), https://www.bloomberg.com/news/articles/2023-08-31/france-earmarks-4-billion-to-support-low-carbon-hydrogen-output; Shoko Oda, *Japan May Open $20 Billion Hydrogen Plan Applications in Summer*, Bloomberg (Jan. 30, 2024), https://www.bloomberg.com/news/articles/2024-01-30/japan-may-open-20-billion-hydrogen-plan-applications-in-summer.

hydrogen in the volumes required for successful commercial liftoff. The proposed rule does not even mention these implications.

IV. The Proposed Rule's Incrementality Requirement is Arbitrary and Capricious.

Apart from a lack of statutory authority, Treasury's proposed incrementality requirement rests on a demonstrably false assumption: There is no basis for concluding that "new" non-emitting generators serving hydrogen production facilities will be constructed just to serve those facilities. Instead, the evidence shows that the opposite is true both nationally and in every region of the country. And if the new non-emitting generator would have come online anyway, it makes no difference to grid emissions whether that new non-emitting generator or an existing non-emitting generator is dedicating its power to the hydrogen producer. Either way, megawatts that would serve the grid generally are instead powering hydrogen production and the resulting "induced emissions" are the same. Even CATF/NRDC have acknowledged that if "underlying clean power would have been generated anyway," it does not "actual[ly] avoid[] systemwide emissions."[123]

In fact, the generation resources most likely to provide "incremental" clean energy if used to power hydrogen production are nuclear plants that otherwise would be at risk of retirement. With the expiration of the nuclear production tax credit and end dates of state support programs, more than 20 percent of the nation's nuclear fleet may retire by 2040. If EAC sales from hydrogen production facilities are adequate to enable these facilities to stay online, or even undergo NRC relicensing, that *would* truly be incremental. The proposed rule acknowledges the possibility of accommodating avoided retirements, but specific text is excluded from the draft regulation, and the proposed solutions are inadequate. This only confirms the arbitrariness of the proposed rule's distinction between new and existing generation.

A. The Proposed Incrementality Requirement is Unnecessary and Illusory.

1. National Trends Confirm the Grid is Decarbonizing.

In assessing a need for incrementality in the first place, Treasury ignores the national trend towards a cleaner grid. Over the 20 years between 1990 and 2010, the percentage of net generation of non-emitting resources was flat at about 30 percent.[124] But in the 12 years between 2010 and 2022 (the latest available data), the figure increased by *one-third* to 40 percent. Notably, as the EIA reported, in the *one year* "[b]etween 2021 and 2022, utility-scale solar generation grew by 26 percent and wind generation by 15 percent," helping to "contribute[] to the decrease in the carbon intensity of electricity."[125]

For at least three reasons, the trend toward zero-emitting generation is expected not only to continue but accelerate. First, the cost of constructing new non-emitting generators is decreasing

[123] CATF/NRDC April Comment Letter at 3.

[124] U.S. Energy Info. Admin., *U.S. Energy-Related Carbon Dioxide Emissions, 2022*, at 5 (Nov. 2023), https://www.eia.gov/environment/emissions/carbon/pdf/2022_Emissions_Report.pdf.

[125] *Id.* at 6.

rapidly. The International Renewable Energy Agency, for example, reported that between 2010 and 2021, the cost of new utility-scale solar, onshore wind, and offshore wind units dropped by 89 percent, 69 percent, and 59 percent, respectively.[126]

Second, complementing the declining costs, the federal government, through various policies including within the IRA, has provided generous subsidies to support non-emitting resources.[127] In FY 2022, the federal government provided $15.3 billion in renewable-related tax expenditures, nearly three times the level in FY 2016.[128] The IRA will dramatically expand this investment, including an estimated $1.2 trillion in incentives by 2032, which could support $11 trillion in total infrastructure investments by 2050.[129] According to research reviewing the IRA's effects on the power system, the incentives may "increas[e] average annual additions [of low-emitting capacity] by up to 3.2 times current levels through 2035,"[130] and "spur[] substantial emission reductions … of 49 to 83% from 2005 levels in 2030."[131]

Third, further bolstering new entry of non-emitting resources, 23 states, the District of Columbia, and Puerto Rico have adopted 100 percent clean-energy goals by 2050, including some with mandatory compliance.[132] More broadly, 36 states have implemented renewable portfolio standards or other measures requiring utilities to procure various amounts of zero-carbon resources.[133]

Cumulatively, these factors have resulted in a marked shift in new entry towards non-emitting projects. Indeed, in its 2023 report *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, the Lawrence Berkeley National Lab noted that there are

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[126] Int'l Renewable Energy Agency, *Renewal Power Generation Costs in 2022*, at 9-10 (2023), https://mc-cd8320d4-36a1-40ac-83cc-3389-cdn-endpoint.azureedge.net/-/media/Files/IRENA/Agency/Publication/2023/Aug/IRENA_Renewable_power_generation_costs_in_2022_SUMMARY.pdf?rev=a008fb3ef20d4f05b1160b37f837c6dd.

[127] U.S. Env't Prot. Agency, *Summary of Inflation Reduction Act Provisions Related to Renewable Energy* https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy (last updated Oct. 25, 2023).

[128] U.S. Energy info. Admin., *Federal Financial*.

[129] Goldman Sachs, *The US is Poised for an Energy Revolution* (Apr. 17, 2023), https://www.goldmansachs.com/intelligence/pages/the-us-is-poised-for-an-energy-revolution.html.

[130] John E T Bistline et al., *Power Sector Impacts of the Inflation Reduction Act of 2022*, 2024 Envir. Res. Ltrs. 19 (Nov. 30, 2023), https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b/pdf.

[131] U.S. Env't Prot. Agency, *Electricity Sector Emissions Impacts of the Inflation Reduction Act*, at 9-10 (Sept. 2023), https://www.epa.gov/system/files/documents/2023-09/Electricity_Emissions_Impacts_Inflation_Reduction_Act_Report_EPA-FINAL.pdf.

[132] Clean Energy States Alliance, *Table of 100% Clean Energy States*, https://www.cesa.org/projects/100-clean-energy-collaborative/guide/table-of-100-clean-energy-states/ (accessed Feb. 4, 2024).

[133] U.S. Energy Info. Admin., *Renewable Energy Explained: Portfolio Standards*, https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php (updated Nov. 30, 2022).

approximately 1,260 GW of zero-carbon generators active in interconnection queues,[134] *exceeding* both the nameplate capacity of the entire national generation fleet[135] and the estimated capacity of non-emitting generation needed to approach the zero-carbon electricity target.[136] Based on data as of the end of 2022, the Federal Energy Regulatory Commission ("FERC") remarked that "[t]his potential generation is the largest interconnection queue size on record, more than four times the total volume (in GW) of the interconnection queues in 2010, and a 40% increase over the interconnection queue size *from just the year prior*."[137] Importantly, these proposed projects are "widely distributed across the U.S.,"[138] and "every single region has faced an increase in … interconnection queue size."[139]

To be sure, many projects in the queue will not reach commercial operation for various reasons, but FERC has taken steps to reduce barriers to new entry. Most notably, in Order No. 2023, FERC adopted a suite of changes to the interconnection process to remove delays and cost uncertainty, which it identified as two of the largest factors that cause projects to drop out of the queue.[140]

Looking forward, given these and other factors discussed in more detail below, the EIA assessed in its long-term outlook that "renewable power capacity will increase in all regions of the United States…."[141] According to EIA, by the end of the decade, 424 GW of new non-emitting capacity will come online, more than doubling the existing 403 GW of non-emitting capacity.[142] Notably, "[o]nce built and when the resource is available, wind and solar generation outcompete other technologies for system dispatch because they have zero fuel costs."[143] As a result, EIA

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[134] Josheph Rand et al., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022*, Lawrence Berkeley Nat'l Lab'y, at 3 (Apr. 2023) ("Queued Up"), https://emp.lbl.gov/sites/default/files/emp-files/queued_up_2022_04-06-2023.pdf.

[135] *Id.* at 35; U.S. Energy Info. Admin., *Electricity Explained: Electricity Generation, Capacity, and Sales in the United States*, https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php (updated June 30, 2023).

[136] Queued Up at 35.

[137] *Improvements to Generator Interconnection Procedures and Agreement*, 184 FERC ¶ 61,054 at P 38 (2023) ("Order No. 2023"), *set aside in part*, 185 FERC ¶ 61,063 (2023). FERC did not break out emitting and non-emitting resources, but as *Queued Up* notes, more than 90% of the queue is comprised of non-emitting resources. Queued Up at 3.

[138] *Id.*

[139] Order 2023, 184 FERC ¶ 61,054 at P 38.

[140] Order No. 2023, 184 FERC ¶ 61,054.

[141] U.S. Energy Info. Admin., *Annual Energy Outlook AEO2023* (Mar. 2023), https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf ("AEO2023").

[142] U.S. Energy Info. Admin., *Annual Energy Outlook 2023*, Table 56 (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=67-AEO2023&cases=ref2023&sourcekey=0 ("Ref. Case Table 56").

[143] AEO2023 at 11.

expects that "U.S. coal-fired generation capacity will decline sharply by 2030 to about 50% of current levels," and there will be decreased "reliance on natural gas in favor of renewables."[144]

This historical trend and projections for a cleaner grid demonstrate that Treasury's proposed rule is arbitrary and capricious in two ways.

First, there is no need for incrementality. The grid is becoming cleaner following technological advances and governmental policies. In its recent proposed rule to control greenhouse gas emissions from power plants under the CAA, EPA itself indicated that the concerns from some NGOs that "existing non-emitting assets will channel electricity from the grid toward electrolyzers" "should mitigate over time as the carbon intensity of the grid is projected to decline."[145] Treasury does not acknowledge the clear trend and EPA's own projections, let alone adapt its proposed rule to them.

Second, as discussed in greater depth in the next section, even if Treasury presented modeling or other evidence justifying its incrementality requirement—and there is none—there is no basis to conclude that restricting EACs for § 45V to "new" resources will affect the level of new renewable entry. As noted, the EIA electric sector modeling in the 2023 Annual Energy Outlook projects that *424 gigawatts* of new zero-emission capacity will be built between 2023 and 2030, which more than doubles the 403 gigawatts of existing zero-carbon capacity as of 2022. [146] These projections explicitly do not consider any additional support provided by the § 45V tax credit. Rather, all of this capacity—both new and existing—is projected to be built and/or remain in operation without any benefit from § 45V-linked EAC sales and without any additional demand from electrolytic hydrogen production. Yet Treasury's proposed rule arbitrarily designates the 424 gigawatts of new capacity as fully incremental and the 403 gigawatts of existing capacity as not incremental, even though both types will be built and operated without any benefit from § 45V. In light of these policy fundamentals, distinguishing between new and existing clean generation is arbitrary and capricious.

2. Regional Analysis Confirms That There is No Basis to Distinguish Between "New" Generators and Existing Resources.

A region-by-region analysis confirms that under current market conditions, an incrementality requirement in virtually all cases will not actually drive incremental renewable generation, but instead just result in hydrogen producers using new renewable generation that would have entered regardless and served other users on the grid. Thus, from the standpoint of grid emissions, using new clean generation for hydrogen production is no different from using existing clean generation.

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[144] *Id.* at 13.

[145] U.S. Env't Prot. Agency, Proposed Rules, New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units, 88 Fed. Reg. 33,240, 33,311, 33,409 (May 23, 2023).

[146] U.S. Energy Information Administration, *Annual Energy Outlook 2023*, March 16, 2023, Appendix Table 1 and Supplemental Reference Case Table 56.

Each of the states can be divided into four groups:

Group 1 – *Competitive markets with high demand for EACs and constrained supply*: In the mid-Atlantic, parts of the Midwest, and New England, existing demand for renewable EACs exceeds available supply, and new entry is constrained. Because new non-emitting units will enter the market with or without inducement by a § 45V credit, and there is no ability to expand new renewable entry further in response to the additional load caused by hydrogen production, it makes no difference whether hydrogen production facilities obtain EACs from new or existing clean resources. Either way, the clean resources would otherwise be serving load.

Group 2 – *Single-market states with enforceable net-zero goals*: New York and California each have single-state power markets and enforceable zero-emissions electricity generation goals. Accordingly, any new entry to support expanded grid demand—including for hydrogen production—will be from non-emitting resources. If hydrogen production is served by existing resources, it will be backfilled by new renewable resources. There is no distinction between EACs from new or existing resources. Other states requiring 100 percent zero-emitting power—including Connecticut, Illinois, Michigan, Minnesota, New Jersey, Virginia, and Washington—are similarly situated even though utilities in those states participate in broader energy markets or are vertically integrated or both; they are all also included in other groups.

Group 3 – *States with competitive markets where renewable units are economic*: In Texas, despite meager state support, developers have brought 58 GW of renewables to commercial operation (compared to a peak load of about 80 GW), and another 30 GW are expected by the end of the decade,[147] demonstrating that they are economic. Further, almost all new entry of generation in recent years in Texas has been by renewable and storage resources. It is therefore reasonable to expect increased grid demand to be met with new renewable entry, regardless of any incrementality requirement.

Group 4 – *States with vertically integrated utilities that are not incented to sell EACs*: In much of the country, generators are owned by vertically integrated utilities that are subject to cost-of-service rate regulation. Under that regulatory construct, revenues from EACs supporting § 45V credits would be passed through to customers. Decisions to construct new renewable units are instead based on extrinsic factors, including state policies, regulatory preference, and system needs. Because new renewable entry is fixed by factors exogenous to the § 45V credit, an incrementality requirement will not incentivize any

[147] Ref. Case Table 56.

incremental new clean generation, but instead will simply result in generation that otherwise would have served load being used for hydrogen production.

We consider each of these groups in more detail below.[148] Although the market conditions differ from group to group, the upshot is the same: an incrementality requirement is arbitrary. In most cases, it will not drive incremental renewable generation, but instead will simply use new generation that would have entered anyway. From the standpoint of grid emissions, the impact is no different than if the hydrogen producer procured electricity from an existing clean generator.

<u>Group 1 – Competitive Markets – PJM and ISO-NE:</u>

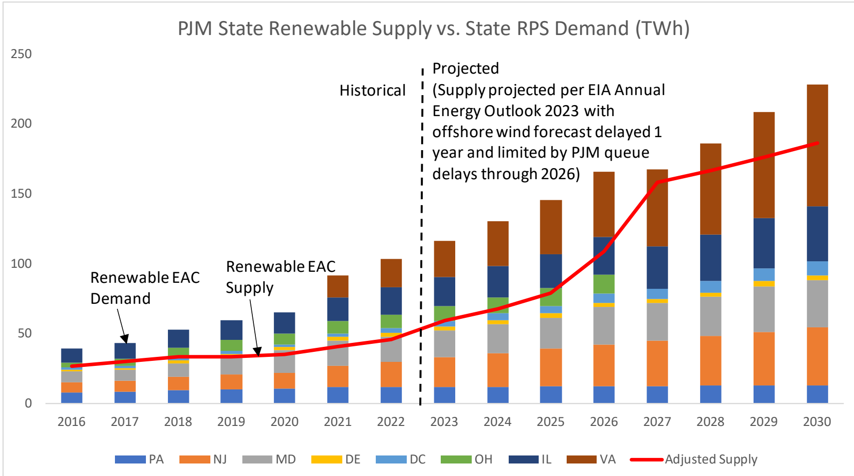
PJM and ISO-NE collectively cover the mid-Atlantic, parts of the Midwest, and New England states:[149]

In these regions, many states have adopted aggressive renewable energy standards requiring utilities to procure EACs—typically from resources within their respective regions. Due to these renewable energy standards, demand for renewable EACs has outstripped supply. Notably, because these standards generally increase over time as states work towards achieving their clean energy goals, the shortage will likely continue through this decade and beyond. The existing and projected shortage can be observed below in Figure 1 for PJM and Figure 2 for ISO-NE:

[148] The attached report presents additional detail on the analyses and conclusions supporting this subsection. *See* Aaron Patterson et al., *Assessing the Incrementality Requirement Proposed in Treasury's 45V Regulations*, The NorthBridge Group (Feb. 2024).

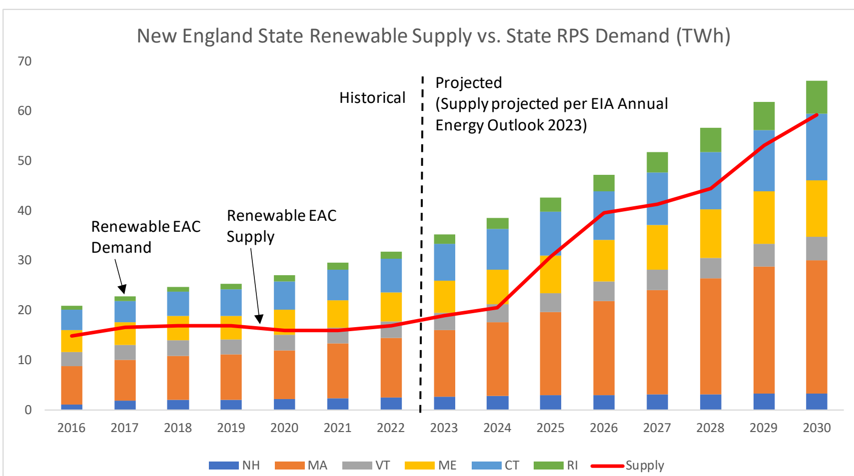
[149] Fed. Energy Regul. Comm'n, *Electric Power Markets*, https://www.ferc.gov/electric-power-markets (last updated May 16, 2023).

Figure 1



Source: EIA Electric Power Annual (state level load and renewable generation). EIA Annual Energy Outlook 2023. Database on State Incentives for Renewables (DSIRE) from the NC Clean Energy Technology Center at North Carolina State University. Totals do not include states with only a small fraction of load within the PJM region (IN, MI, KY, NC) and assume that 70 percent of Illinois demand and renewable production is located within PJM.

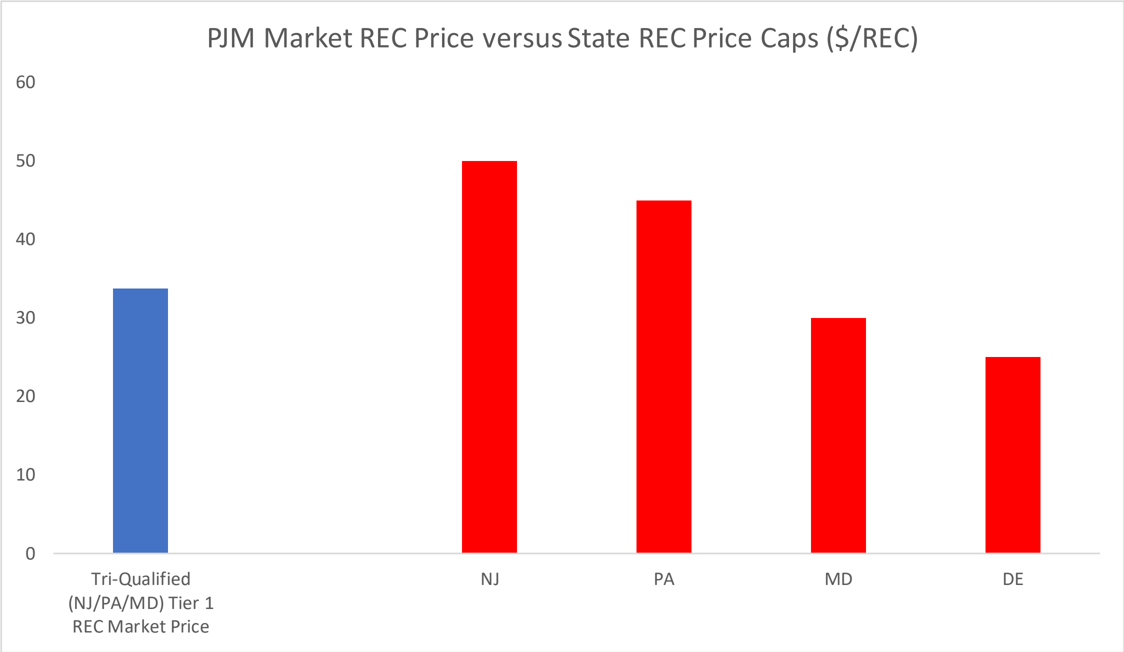
Figure 2



Source: EIA Electric Power Annual (state level load and renewable generation). EIA Annual Energy Outlook 2023. Database on State Incentives for Renewables (DSIRE) from the NC Clean Energy Technology Center at North Carolina State University.

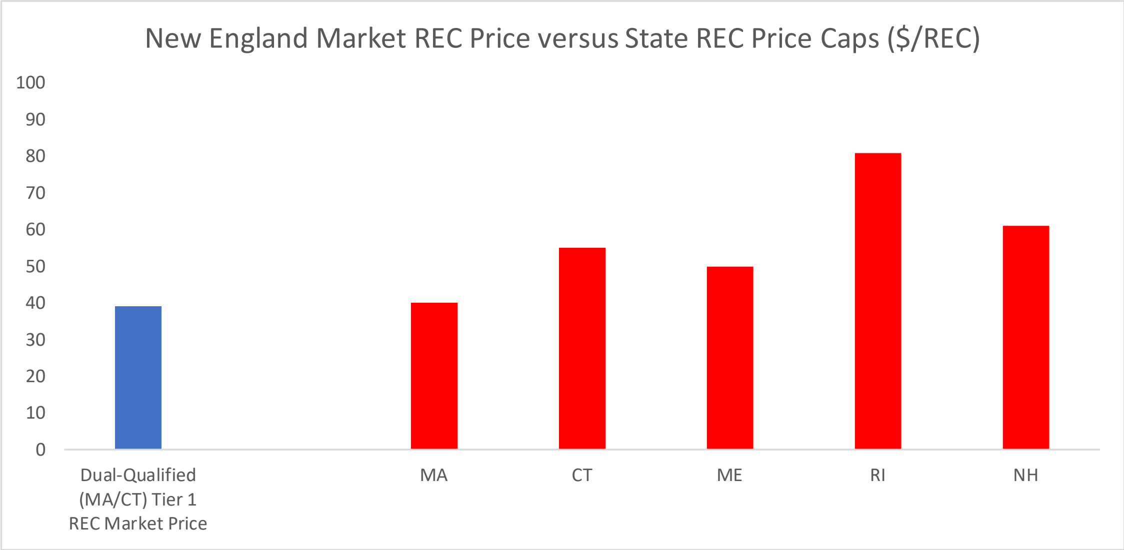
Recognizing that supply shortages can preclude utilities from complying with renewable energy standards, states typically allow utilities to meet their obligations through alternative compliance payments—*i.e.*, cash payments that substitute for EACs. In PJM and ISO-NE, the market cost of EACs is currently at or above the alternative compliance payment amounts for multiple states, indicating that existing demand for EACs is going unmet and that additional EAC demand—such as from hydrogen production—would drive further unmet demand:

Figure 3



Source: Lawrence Berkeley National Laboratory (Galen Barbose), *U.S. State Renewable Portfolio & Clean Electricity Standards: 2023 Status Update*, June 2023 at 34 (REC price estimated from graphic). https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf. More recent REC prices observed in over-the-counter markets are at similar levels.

Figure 4



Source: Lawrence Berkeley National Laboratory (Galen Barbose), *U.S. State Renewable Portfolio & Clean Electricity Standards: 2023 Status Update*, June 2023, at 34 (REC price estimated from graphic). https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf. More recent REC prices observed in over-the-counter markets are at similar levels.

Although PJM and ISO-NE are working to address some of the root causes of the supply constraints, especially through interconnection queue reform, other barriers to entry—including siting challenges and transmission topography—are unlikely to change.

These grid conditions mean that an incrementality requirement will not drive any incremental entry of renewable generation. Rather, there is already more demand for clean generation than ability to supply, and any new clean generator coming online would have entered regardless of the incrementality requirement. Such a generator will be used to serve grid load if it is not used to produce hydrogen—just as any existing non-emitting generator will be used to serve grid load if not used to produce hydrogen. Indeed, the only truly incremental clean resources under these market conditions are nuclear units that, but for the ability to sell EACs to hydrogen producers, would otherwise retire. As a result, hydrogen producers in PJM or ISO-NE do not create more "induced emissions" if they are served by new rather than existing clean resources. Distinguishing between the two is arbitrary.

Group 2 – Single-Market States with Enforceable Carbon Limits (California and New York):

New hydrogen production is unlikely to result in new grid emissions in single-state power markets with strict net-zero emission goals—for example, California and New York. Both states have enforceable decarbonization goals, including renewable energy standards and a requirement to achieve 100 percent zero-carbon generation—by 2040 in New York and 2045 in California. As a result, when grid demand increases, including because hydrogen producers come online, only non-emitting generators can feasibly enter the market to serve that new load. Accordingly, system-wide emissions will be the same, regardless of whether the hydrogen facility sources its power from new or existing clean generators.

Connecticut, Hawaii, Illinois, Michigan, Minnesota, New Jersey, Rhode Island, Virginia, and Washington—to name a few states—are similarly situated, though they also fall into Group 1 (utilities in competitive markets) or Group 4 (vertically integrated utilities). Each of these states has adopted aggressive, enforceable requirements to reach net-zero power generation by the middle of the century:

State	Requirement
Connecticut	100% carbon-free electricity by 2040[150]
Hawaii	100% renewable energy by 2045[151]
Illinois	100% clean energy by 2050[152]
Michigan	100% clean energy by 2040[153]

150 Conn. Gen. Stats. § 22a-200a(a)(3).

151 Haw. Rev. Stat. § 269-92(a)(6).

152 20 ILCS § 3855/1-5(1.5).

153 Mich. Comp. Laws § 460.1051(1)(b) (eff. Feb. 27, 2024).

Minnesota	100% carbon-free energy by 2040[154]
New Jersey	100% clean energy by 2035[155]
Rhode Island	100% renewable energy by 2033[156]
Virginia	100% zero-carbon energy by 2045 or 2050[157]
Washington	100% carbon neutral by 2030; 100% carbon free by 2045[158]

In these states, as in California and New York, compliance with state law directly or practically requires that new non-emitting generators enter to supply increases in grid demand, whether from hydrogen producers or other users. Therefore, when hydrogen producers enter service, system-wide emissions should not change whether the hydrogen producer obtains EACs from existing non-emitting resources or new ones.

<u>Group 3 – States with Competitive Markets Where Non-Emitting Generation is Economic (Texas):</u>

The economics of power generation in the ERCOT region strongly suggest that an incrementality requirement will not drive new renewable generation because such generation already is economic without the hydrogen production tax credit. As of 2023, there were approximately 58 GW of renewables in ERCOT, compared to a peak load of 80 GW.[159] The first two months of 2024 have seen record solar output in ERCOT, including a new peak and a 46 percent increase in megawatt-hours delivered between January 2023 and January 2024.[160] Looking forward, over 95 percent of Texas's interconnection queue is renewable,[161] and a further 30 GW are expected to be built in ERCOT by 2030.[162] Unlike in the first two groups discussed above, the entry of renewables in Texas is driven almost entirely by market forces and federal tax credits; Texas has already met its renewable portfolio standard target many times over and renewable EACs in the region are priced at levels consistent with voluntary corporate demand, at an order of

154 Minn. Stat. § 216B.1691(2g)(3).

155 N.J. Exec. Order 315 (Feb. 15, 2023) (requiring the New Jersey Board of Public Utilities to adopt enforceable standards during 2024).

156 R.I. Gen Laws § 39-26-4(14).

157 Va. Code Ann. § 56-585.5(C).

158 Wash. Rev. Code §§ 19.405.040(1), 19.405.050(1).

159 *E.g.*, Electric Reliability Council of Texas, *Fact Sheet* (Feb. 2024), https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf.

160 Dennis Wamsted, *Momentous Changes On the way in ERCOT as Texas Renewable Transition Rolls On*, Inst. for Energy Econ. & Fin. Analysis (Feb. 14, 2024), https://ieefa.org/resources/momentous-changes-way-ercot-texas-renewable-transition-rolls.

161 Garrett Hering, *California ISO Tackles 'Broken' Interconnection Process as Queue Tops 500 GW*, S&P Global (July 19, 2023), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/california-iso-tackles-broken-interconnection-process-as-queue-tops-500-gw-76499753.

162 *Id.*

magnitude less than the level seen in the PJM and ISO-NE regions. This confirms that developers have determined that new renewable entry is economic. Accordingly, to the extent that new entry is required to meet increased electricity demand resulting from hydrogen production, the market has demonstrated that renewables are the technology of choice to meet it. There is no reason to require incrementality.

Group 4 – States with Vertically Integrated Utilities:

The final group is also the largest, and comprises states where generation is built and owned by vertically integrated utilities. In these states, comprising the Southeast, Great Plains, much of the Midwest, and much of the West (apart from California), generators are built under the traditional cost-based rate model, where revenues from the sale of EACs are passed on to the customers funding that generation. In these areas, the sale of EACs, such as to hydrogen producers, merely lowers the net cost of providing service and does not influence decisions as to what generators to construct. Those decisions are driven by other considerations, including the need to comply with renewable energy standards, regulatory preference, and system needs. Therefore, a new non-emitting plant selling EACs to a hydrogen producer likely would have come online regardless. Once again, from the standpoint of grid emissions, it makes no difference whether a hydrogen producer in that service territory obtains its EAC from a new or existing resource.

Consider for example a hypothetical utility in a state that maintains a 40 percent renewable energy standard. If 3 TWh of new energy demand is placed on the system by hydrogen producers, the utility may choose to construct non-emitting generators necessary to comply with its state requirement or integrated resource plan, but the balance will be up to other factors.

* * *

In sum, an incrementality requirement only makes sense when the § 45V credit actually drives new incremental clean generation that, but for the tax credit, otherwise would not have entered operation. But there is not a single region in the United States where that is broadly true. Rather, in every region, new renewables serving hydrogen producers mostly would have entered regardless, and if they were not powering electrolyzers, they would be powering other grid users. Under these conditions, an incrementality requirement does not avoid any induced grid emissions. In fact, recent modeling from EPRI showed that total emissions increase even with the three pillars in place due to this resource shuffling.[163] This stands in contrast to the bare assertions (unsupported by modeling or analytics) from DOE's and EPA's supporting materials that when EACs from low-GHG generators have attributes that meet these three criteria, "it would be reasonable to treat induced grid emissions as zero."[164] Indeed, if induced emissions are considered as part of the lifecycle analysis for § 45V, both new and existing resources would be ineligible for the tax credit.

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[163] Elec. Power Rsch. Inst., *Impacts of IRA's 45V Clean Hydrogen Production Tax Credit* (Nov. 3, 2023), https://www.epri.com/research/products/000000003002028407.

[164] *DOE Guidelines* at 12; EPA Letter at 6 ("it would be reasonable to expect that the purchase and use of zero-emitting electricity represented by three-pillar EACs does not result in induced grid emissions.").

This could not have been what Congress intended in setting up a new program to incentivize the production of clean hydrogen.

B. The Three-Year Legacy Exemption Confirms the Proposed Rule is Arbitrary and Capricious.

Treasury's decision to allow hydrogen production facilities to use EACs from generators that entered operation up to 36 months before the hydrogen production facility confirms the arbitrariness of the proposed rule. Plainly, even putting aside the analysis in subsections (1) and (2) above, it is difficult to see how EACs from a 36-month-old unit are any different from EACs from other existing units. Neither Treasury, EPA, nor DOE attempted to draw such a distinction. Even accepting for the sake of argument that incrementality is necessary, there is nothing "incremental" about a three-year old unit. Such a unit can either serve grid load or a hydrogen producer. This internal inconsistency suggests the proposed rule supports an unlawful preference towards "new" (or, more accurately, "newer") units rather than any genuine concerns about induced grid emissions.

C. There is No Justification for Treating Nuclear Uprates Differently Than New Generation.

To the extent Treasury adopts an incrementality requirement, it is reasonable to consider uprates to be incremental, as outlined in the proposed rule. Existing nuclear units are limited by their physical equipment and NRC licenses to a given maximum thermal capacity output. A nuclear operator can make improvements to a nuclear unit over its operating life to increase its output, including by installing new monitoring equipment, updating instrumentation, modifying existing generation equipment, or installing more efficient equipment. Although these initiatives can improve plant output between 1.7 and 20 percent, they can cost up to $1 billion.

As the proposed rule recognizes, uprates are virtually indistinguishable on a grid basis from new entry. In both cases, new megawatts of capacity are contributed to the grid. And both uprates and new entry require significant planning and investment. The only distinction is whether the new megawatts are added to an existing unit or a new one—but that is inapposite to any of Treasury's concerns. Any final rule incorporating an incrementality requirement should be neutral as between new entry and uprates.

V. Potential Revisions to the Incrementality Requirement.

Treasury should not finalize an incrementality requirement for the reasons discussed above, but if it nonetheless does, it should incorporate three revisions to reflect circumstances under which an EAC from an existing carbon-free generation resource may be deemed to satisfy the incrementality requirement. Adopting these proposals will better align the final regulations with grid realities and mitigate harm to the hydrogen industry.

<u>Increase Formulaic Alternative for Existing Clean Resources to 10 Percent</u>. Recognizing that § 45V credits may avoid retirements, Treasury is considering an alternative compliance provision that "would deem five percent of the hourly generation from minimal-emitting electricity generators (for example, wind, solar, nuclear, and hydropower facilities) placed in service before Jan. 1, 2023, as" able to provide EACs to clean hydrogen producers.[165] Treasury uses its five percent formula, among other things, as a proxy for avoided retirements.[166] NEI supports a formulaic approach to allowing a portion of existing generation capacity to satisfy the incrementality requirement, but the approach must reflect a valid proxy and the volumes must be sufficient to support a sustainable hydrogen industry. Increasing the level from five percent to at least ten percent, measured at the company and not facility level, is essential to satisfying both components.

First, Treasury's proposed five-percent figure does not reflect a reasonable proxy for nuclear retirements. In finding a risk that five percent of the nuclear fleet may retire through 2032, Treasury ignores that the nuclear production tax credit will expire after 2032.

In the decade prior to the passage of the IRA, 13 reactors representing 10.2 GW of nuclear capacity retired, with most retirements driven by economic factors. At the same time 20 reactors representing 20.3 GW of capacity sought and obtained state-based support to avoid retiring. Collectively, these reactors represented 30 percent of the total nuclear capacity and more than half of the non-regulated merchant nuclear capacity operating as of 2012.[167] These units have remained in service because of federal and state programs to support their operation. Much of the state support—including in Illinois, New York, and Connecticut—however, will terminate in the next few years, well before 2033. Thus, nuclear plants face a revenue cliff beginning in 2033, when the § 45U nuclear production tax credit sunsets. The same Princeton University researchers arguing in favor of the proposed incrementality requirement recognize elsewhere that a wave of further nuclear retirements is expected once the nuclear production tax credit is no longer available.[168] The EIA projections that Treasury cites to support its five percent estimate recognize this same reality, projecting retirements to exceed ten percent in 2033 and more than double to 22 percent by 2040.[169] Selling EACs to hydrogen producers eligible for production tax credits can provide a

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[165] NPRM, 88 Fed. Reg. at 89,231.

[166] *Id.* at 89,231-32.

[167] Retired reactors include Crystal River 3 (Regulated, 2013), Kewaunee (2013), San Onofre 2&3 (Regulated, 2013), Vermont Yankee (2014), Ft. Calhoun (Regulated, 2016), Oyster Creek (2018), Pilgrim (2019), Three Mile Island 1 (2019), Indian Point 2&3 (2020/21), Duane Arnold (2020), and Palisades (2022). Merchant reactors obtaining state support have included Quad Cities 1&2, Clinton, Dresden 2&3, Byron 1&2, Braidwood 1&2, Ginna, Fitzpatrick, Nine Mile Point 1&2, Salem 1&2, Hope Creek, Millstone 2&3, Davis-Besse, and Perry (state support legislation passed but later repealed for the final two).

[168] *See* Qingyu Xu et al., *Cleaner, Faster, Cheaper: Impacts of the Inflation Reduction Act and a Blueprint for Rapid Decarbonization in the PJM Interconnection*, Princeton University Zero Lab 24 (Dec. 2022), https://zenodo.org/records/7429042/files/PJM_Deep_Decarbonization.pdf ("[F]ollowing expiration of the IRA production tax credit for existing nuclear in 2032 (and absent equivalent sustained support), PJM's nuclear fleet will once again face the threat of economic retirements. Nuclear plant closures and load growth from electrification would then lead to an increase in natural gas-fired generation in 2035, resulting in higher emissions than in 2030, despite continued growth of wind and solar.").

[169] U.S. Energy Info. Admin., *Annual Energy Outlook 2023, Table 9 (Electric Generating Capacity, Reference Case)*, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2023&cases=ref2023&sourcekey=0 (last accessed Feb. 20, 2024).

key source of revenue to stabilize these generators' economics and allow them to continue operating.

Critically, Treasury also overlooks that the timing for greatest retirement risk aligns with the timing for the greatest needed increase in hydrogen production volumes. As discussed above, under DOE's hydrogen pathways, clean hydrogen production will rise from near-zero now to ten million metric tons by 2030, and then quintuple between 2030 and 2050.[170] With this trajectory, about 75 percent of the hydrogen production volumes eligible to claim the § 45V credit will fall in the 2033-45 period. Failing to consider EIA's projection of retirements after 2032 ignores the period when EACs will be in the greatest demand, and when EAC purchases may avoid the greatest number of retirements.

Second, the five percent limit will not be sufficient to satisfy hydrogen producers' demand for EACs. In the aggregate, the proposed five percent level is a ceiling—it can only be met if every eligible facility sells its full five percent allotment to hydrogen production facilities. But that is unlikely because over 60 percent of non-emitting capacity is owned by vertically integrated utilities focused on serving native load rather than hydrogen production. It is also unreasonable to assume that every other eligible facility will use its full five percent allotment for hydrogen producers rather than other EAC purchasers. Thus, in practice, EACs representing far less than five percent of the existing non-emitting capacity will be available to hydrogen producers under the contemplated five percent allowance.

Access to a meaningful volume of EACs to support the § 45V credit is essential for hydrogen production to be economic. Producers must run electrolyzers near capacity to offset the high capital costs of entry and require an adequate supply of EACs to support that operation. Without an adequate supply of EACs, prospective entrants may decide that hydrogen production is not likely to be viable. Allowing ten percent of existing clean capacity to be treated as incremental would ensure that EACs can be allocated efficiently, particularly by enabling owners of uncommitted clean generators to benefit from the economics of scale in selling to large hydrogen producers, and by ensuring that those producers have access to an adequate supply of credits.

To further address these issues, Treasury should measure the ten percent threshold at the owner level rather than the facility level. As mentioned above, not every nuclear plant will power hydrogen production, and hydrogen production projects need to be relatively large to achieve economies of scale. Requiring hydrogen production to be tied to, and limited by, available supply from a particular generator would require hydrogen projects to be configured on a small scale, undermining economics and preventing technology deployment and scaling. Measuring the ten percent at the fleet level for each company would provide flexibility to tailor the size of hydrogen projects to the total pool of available generation that otherwise complies with applicable requirements, *i.e.*, no more than ten percent of the company's total carbon-free generation being

[170] Pathways Report at 6, 68.

used for hydrogen production and subject to any applicable temporal or geographic limitations adopted in the final regulations.

Treasury should not credit recent analytics suggesting that even a five percent allowance could raise greenhouse gas emissions significantly. In its paper *How Clean Will US Hydrogen Get*, the Rhodium Group attempts to evaluate the effect of Treasury's proposed five percent allowance, but in doing so, it assumes a baseline where *no* nuclear units retire, and all licenses are renewed.[171] Rhodium's own research has shown that over half of the nation's merchant nuclear fleet is at risk of retirement without policy support.[172] Moreover, Rhodium's estimates appear to assume full utilization of the five percent allowance by all resources, which likewise is not reasonable. The same reasons why these assumptions are wrong explain why an allowance of at least 10 percent is appropriate. Likewise, Energy Innovation's recent report discussing Treasury's proposed formulaic approach to retirements suffers from similar flaws.[173] The report acknowledges the risk of nuclear retirements, but its emissions analytics assume that nuclear units will continue operating.[174]

Nor should Treasury impose convoluted, burdensome tests to assess whether individual nuclear units are at risk of retiring.[175] As just discussed, EIA and DOE projections confirm that nuclear retirements will rise in the 2030s, just as hydrogen production will be increasing. And in a paper preceding the IRA, Rhodium warned that without policy support, as much as half of the country's nuclear fleet could retire by 2030.[176] Thus if anything, even a ten percent formulaic threshold would undercount the nuclear retirement risk that will be seen after the nuclear production tax credit expires in 2032. Further restrictions on the formulaic alternative, therefore, would serve only to reduce hydrogen production and hasten the premature retirement of clean generators.

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[171] Ben King et al., *How Clean Will US Hydrogen Get? Unpacking Treasury's Proposed 45V Tax Credit Guidance*, Rhodium Group (Jan. 4, 2024), https://rhg.com/research/clean-hydrogen-45v-tax-guidance/.

[172] John Larsen & Whitney Jones, *Nukes in the Crosshairs Revisited: The Market and Emissions Impacts of Retirements*, Rhodium Group (Nov. 4, 2016), https://rhg.com/research/nukes-in-the-crosshairs-revisited-the-market-and-emissions-impacts-of-retirements/ ("Nation-wide we estimate that roughly one-half of the nation's nuclear plants located in competitive markets are at risk of early retirement. The economics of nuclear plants in regulated regions are also being drawn into question as well. In total, we estimate an additional 24 GW of nuclear generating capacity could close across the country between now and 2030 unless additional policy steps are taken."); *see also* John Larsen et al., *Pathways to Build Back Better: Investing in 100% Clean Electricity*, Rhodium Group (Mar. 23, 2021), https://rhg.com/research/build-back-better-clean-electricity ("Under current policy more than half of the nuclear fleet will retire by 2030, leaving a huge gap.").

[173] *See* Energy Innovation Policy & Technology LLC, 45V Exemptions Need Strong Guardrails to Protect Climate, Grow Hydrogen Industry (Feb. 2024), https://energyinnovation.org/wp-content/uploads/2024/02/Energy-Innovation-45V-Exemptions-Need-Strong-Guardrails.pdf ("Energy Innovations Report").

[174] *Id.* at 15, 16-17.

[175] *Id.* at 19-27.

[176] *See* Pathways to Build Back Better.

Finally, Treasury must acknowledge that the revenue from EAC sales to nuclear generators could be a key factor in owners' decisions not to retire. When combined with market revenues, the § 45U nuclear production tax credit is a reasonable proxy for the ongoing costs and risks of operating a nuclear plant, and is equivalent to all-in revenue ranging from $43.75/MWh in 2024 to about $55/MWh in 2033, with expected inflation. This suggests that, without additional revenue streams such as sales of EACs to hydrogen producers, nuclear operators may view it more economic to stop operating once the § 45U nuclear production tax credit sunsets—which is what the EIA data cited by Treasury shows, with nuclear retirements doubling to ten percent in 2033 and more than doubling to 22 percent by 2040. But nuclear facilities offer a host of benefits, including stable, reliable, and carbon-free operations during all hours. The continued operation of nuclear plants after 2032 would reduce emissions by over 300 million tons of CO2 per year, compared to replacement by natural gas combined cycle generation. The merchant fleet alone would over 120 million tons of CO2 per year.[177] To the extent Treasury adopts an incrementality requirement, it should do so in a way that is tailored to avoiding premature nuclear retirements.

Nuclear License Renewals. In addition to the proposed formulaic allowance for existing clean generation, Treasury should treat nuclear units that apply for a license renewal as "incremental."

Initial nuclear operating licenses are for 40 years, but nuclear generators can seek subsequent licenses to operate for 20 years at a time. This is a significant business decision. The license process is both lengthy and costly, often taking five or more years to complete. Moreover, relicensing and then operating a nuclear facility for the 20-year renewed license period requires that the operator make significant capital improvements and ongoing operational expenditures. Even without consideration of the cost of risk and any return on capital, the average nominal cost of relicensing and operating a typical U.S. reactor over a 20-year license period is approximately $8 billion,[178] and the 20-year present value of non-fuel capital expenditures and O&M needed to re-license and operate a nuclear plant is approximately $2,950/kW.[179]

Relicensing the nation's nuclear fleet is one of the most important steps the country can take to affordably and reliably decarbonize the power sector and broader economy.[180] But nuclear plants need adequate revenue streams to make the investments needed to pursue license extensions and continue operation. Roughly one-third of the existing nuclear capacity in the United States

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177 Figures based on total nuclear generation of 770 TWh/year; merchant generation of 300 TWh/yr; and estimated marginal emissions rate for NGCC of 0.4 tons of CO2 per MWh.

178 Based on costs from the *Nuclear Costs in Context* (December 2023) Report from NEI with 2022 costs escalated at inflation and evaluated over a 2030 to 2049 relicense period for an average U.S. nuclear reactor capacity of 1,030 Megawatts.

179 National Renewable Energy Laboratory, 2023 Annual Technology Baseline, https://atb.nrel.gov/electricity/2023/index (accessed Feb. 5, 2024). The net present value of nuclear costs is calculated using a 8.5% discount rate, consistent with the rate assumed for new nuclear in the Annual Technology Baseline.

180 Son H. Kim et al., *The Carbon Value of Nuclear Power Plant Lifetime Extensions in the United States*, 208 Nuclear Tech. 775 (2022), https://www.tandfonline.com/doi/full/10.1080/00295450.2021.1951554.

will require a license renewal between 2030 and 2040, just as the § 45U nuclear production tax credit is expiring and hydrogen production is ramping up. Allowing these nuclear units to sell § 45V-eligible EACs to hydrogen facilities may provide the business case to pursue relicensing and secure authorization to operate for another 20 years.

For nuclear operators that do seek relicensing, Treasury should treat nuclear capacity as incremental five years prior to the anticipated start date of the license. Under NRC regulations, nuclear power plant operators must submit their renewal applications "at least 5 years before the expiration of the existing license" to avoid a lapse.[181] The relicensing process can in fact take even longer, and many plant owners apply more than five years before the license expires. Accordingly, treating nuclear capacity as incremental beginning five years prior to the license expiration will respect the operator's decision to move forward with relicensing and align the economic incentive of producing clean hydrogen with that decision.

Finally, to be clear, treating nuclear plants seeking relicensing as "incremental" would be independent of the formulaic ten percent allowance discussed above. The entire output of the nuclear unit undergoing relicensing should be deemed incremental because if a nuclear plant is not relicensed, the entire plant's capacity disappears; conversely, if a plant is relicensed, the entire plant's output remains available. Treasury should reject the suggestion that only the portion of a relicensed nuclear plant "absolutely necessary to keep the facility operational" should be able to sell EACs used for clean hydrogen production, an amount to be calculated based on a showing of need.[182] Treasury does not propose to limit eligible EACs to the share of new renewable plants "only" to the extent "absolutely necessary" to bring the facility into operation; there is no basis for treating nuclear plants seeking relicensing any differently. That is especially so because relicensing a nuclear plant is a binary decision: either the plant is relicensed, or it is not. There is no way to relicense only a fraction of its capacity.

Relief for Early Hydrogen Producers. If Treasury retains its incrementality requirement, it should make an exception allowing the earliest hydrogen production facilities, such as those beginning construction by the end of 2026, to obtain EACs from existing non-emitting resources. To meet the DOE's hydrogen pathway timeline, hydrogen production will have to increase from near zero now to ten million metric tons per year in 2030. These earliest producers, including the hydrogen hubs, will experience many of the most significant challenges in reaching commercial operation, including the highest up-front costs. But they are also necessary to driving demand for hydrogen that will enable the industry to become self-supporting in the future.

This is exactly why Congress provided $8 billion in the IIJA to establish hydrogen hubs in the first place. And it is why DOE is requiring selected hydrogen hubs to be well into Phase 2 of project development by the end of 2026, which includes near completion of engineering and design and expenditures of up to 15 percent of DOE funding. The proposed exception for early producers would allow the hubs to qualify for the full § 45V tax credit based on the beginning of construction

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181 10 C.F.R. § 2.109(b).

182 Energy Innovations Report at 23-24 (asserting that "Treasury should target a share that is only as large as is absolutely necessary to keep the facility operational").

standard utilized in current tax law, especially if planning expenses like engineering and design are included in the five percent expenditure threshold.[183] To reiterate our discussion above, DOE's Hydrogen Strategy and Roadmap emphasizes that hydrogen hubs will "drive scale in production, distribution, and storage to facilitate market liftoff.[184] Each of these factors is needed to establish a new industry from scratch and obtain the long-term decarbonization benefits.

An exception for early movers would also respect their expectations. Planning and fundraising for projects that would begin construction by the end of 2026 is already underway. Much of the financial analysis for these projects was completed before Treasury proposed its incrementality requirement. An exception would ensure that these developers' expectations are not disrupted, helping to ensure they proceed to completion.

This is especially important given the limited ability for developers to obtain EACs from "incremental" non-emitting generation prior to commercial operation. As shown above, there is no opportunity for new renewable entry in many parts of the country, and in other areas, the timeline for new entry can stretch half a decade or more. It is reasonable to exempt this first wave of hydrogen producers from the incrementality requirement when no incremental generation is reasonably available to them. Even under the best circumstances, given queue delays, transmission requirements, and siting disputes, a significant portion of the ten-year subsidy period could be gone by the time a renewable unit could enter.

Finally, the "induced emissions" of these early entrants would be minimal. The exception would cover only a small number of hydrogen projects.

* * *

Each of the above proposals would support Treasury's proposal and Congress's objectives. The first two proposals are consistent with an incrementality requirement, and the last provides a narrow exception to ensure that hydrogen can successfully lift off as Congress envisioned.

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[183] *See* Dep't of the Treasury, Notice of Initial Guidance: Prevailing Wage and Apprenticeship Initial Guidance Under Section 45(b)(6)(B)(ii) and Other Substantially Similar Provisions, 87 Fed. Reg. 73,580, 73,581-82 (Nov. 30, 2022).

[184] Hydrogen Strategy and Roadmap at 2; Pathways Report at 2 (Hydrogen hubs "will advance new networks of shared hydrogen infrastructure.").

Assessing the Incrementality Requirement Proposed in Treasury's 45V Regulations

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Executive Summary

As part of its promulgation of rules for the administration of the hydrogen Production Tax Credit ("PTC") in Section 45V of the Inflation Reduction Act ("IRA"), the Treasury Department has proposed an "incrementality" standard for clean hydrogen production that uses electricity as an input. The stated purpose of this standard is to ensure that clean hydrogen production does not result in significant changes in emissions across the broader power sector. In very simple terms, a clean electric generator supplying a hydrogen producer is incremental under the logic of Treasury's proposed rule if the generator would not exist absent the hydrogen PTC or if the generator's output would be fully replaced with other clean generation. A new generator would be incremental only if it comes on-line due to the hydrogen PTC and an existing generator would be incremental only if it would retire absent the hydrogen PTC or if it would be fully replaced with clean generation.

Treasury's proposed implementation of "incrementality," however, has little to no relation to whether a resource is actually incremental with respect to the hydrogen PTC. Instead, Treasury arbitrarily proposes to treat all new resources as if they would not have come on-line without the hydrogen PTC and all existing resources as if they would have remained on-line regardless and would not be replaced with clean generation. This treatment is inconsistent with both electricity market dynamics and the economic impact of other tax credits contained in the IRA. The underlying economics suggest that in all regions of the country new resources are no more likely to be incremental with respect to the hydrogen PTC than existing resources. In fact, since the non-hydrogen tax credits for new clean resources will continue to be available long into the future and the tax credits for existing clean resources (e.g., the 45U nuclear production tax credit) expire within the next eight years, the economics suggest that new resources are more likely to come on-line without the hydrogen credit than existing resources are to stay on-line without the hydrogen credit. Therefore, Treasury's overly simplistic assumption that new resources are incremental and existing resources are not, is, at a minimum, arbitrary and, in many instances, gets matters backwards.

Introduction

The Treasury Department's notice of proposed rulemaking regarding *Section 45V Credit for Production of Clean Hydrogen*[1] includes proposed rules for calculating the life cycle emissions of hydrogen production. These rules determine to what extent hydrogen producers utilizing electricity as a primary input are able to qualify for the 45V tax credit. A key input into the life cycle emissions calculation is the degree to which the generator providing electricity to the hydrogen producer is "incremental." In the context of the proposed rules, the degree to which the generator is incremental (or its "incrementality") is based on the "induced emissions" resulting from the hydrogen producer's use of a particular electric generator's Energy Attribute Credits ("EACs"), that is, the amount by which system-wide emissions change if the generator is allowed to supply zero-emission EACs to electrolytic hydrogen producers for 45V qualification purposes, compared to a but-for world in which it cannot supply zero-emission EACs. If a hydrogen producer's use of a generator's EACs results in zero or near-zero "induced emissions," the hydrogen producer can qualify for a 45V tax credit, but if the use of the generator's EACs results in material "induced emissions" it cannot, even if the generator does not itself produce any emissions at the point of generation.

While simple in the abstract, whether and to what degree a given generator is incremental is a complex empirical question and the answer can vary considerably with both the type of generator and the electricity market

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[1] *See* Dep't of Treasury, Notice of Proposed Rulemaking: Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election to Treat Clean Hydrogen Production Facilities as Energy Property," RIN 1545-BQ97 (Dec. 22, 2023) ("45V NPRM").

fundamentals and rules that prevail at its location. However, rather than engage with this complexity, Treasury has proposed rules that effectively assume that new zero-carbon electric generators are 100% incremental in all cases, and that existing zero-carbon generators are never incremental.[2] In reality, whether either type of generator is incremental or not depends on a wide range of economic and policy factors that are specific to different regions, time periods, and individual facilities. There are many instances where existing generators may actually be incremental within the meaning used by Treasury – that is, where the use of an existing generator rather than a new generator to power hydrogen production will result in no "induced emissions." And there are many instances where a new generator may be either only partially incremental or not incremental at all because that new generator would have built with or without the existence of 45V.

Numerous exceptions exist to Treasury's simplistic approach to determining incrementality

Based on the advice of DOE, Treasury has partially acknowledged some exceptions to its proposed rule, i.e., limited situations where existing zero-carbon generation may actually be incremental. Specifically, Treasury seeks comment on how it should consider circumstances where there is zero-carbon generation "(i) that would retire absent the ability to sell electricity for qualified clean hydrogen production, (ii) during periods in which minimal-emitting generation would have otherwise been curtailed, if marginal emissions rates are minimal, or (iii) in locations where grid-electricity is 100 percent generated by minimal-emitting generators or where increases in load do not increase grid emissions, for example, due to State policy capping total GHG emissions such that new load must be met with minimal-emitting generators."[3] Treasury's proposed rules themselves do not include these exceptions; rather Treasury simply seeks further comment on whether existing generators in these situations should be considered as incremental based on a facility-by-facility review with the burden of proof on the generator, or alternatively should be accounted for via a standardized allotment that makes 5% of existing zero-carbon generation eligible for 45V-linked EAC sales without a specific burden of proof, in contrast to 100% of new zero-carbon generation being eligible.[4]

Treasury's proposed rules do not consider instances where a new zero-emission generator may not be fully incremental or may not be incremental at all (i.e., results in the same "induced emissions" as an existing generator serving hydrogen production). Instead, Treasury's proposed rules allow new zero-carbon generation to qualify to sell 45V-linked zero-carbon EACs for 100% of their output with no burden of proof at all with respect to their incrementality. Thus, existing and new resources receive starkly asymmetric treatment: new resources are presumed to be 100% incremental, while existing resources are presumed to be completely non-incremental under the base rules. And while Treasury has left open the possibility of modest incremental treatment for existing resources, it proposes either a case-by-case review with little guidance on how each case will be adjudicated, or a small allotment of 5% of existing generation which effectively assumes existing generation is one twentieth as incremental as new.

In reality, this overly simplistic binary rule yields arbitrary results. For example, EAC sales for 45V purposes from an existing zero-carbon generator may result in a net addition of zero-carbon energy relative to the but-for world if:

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[2] As noted below, Treasury seeks comment on certain situations where existing generation may qualify as incremental, but the proposed rules themselves do not include any such exceptions.

[3] 45V NPRM at 37.

[4] 45V NPRM at 38-47.

- **Existing generator would otherwise retire (acknowledged by Treasury).** If an existing zero-carbon generator is not economically viable or would not renew its operating license without the additional revenue from the sale of EACs for 45V purposes, it will retire and its zero-carbon output will be replaced by other generation, much of which will produce emissions. If such a retirement is avoided through the additional revenue from EAC sales for 45V purposes, then the incremental impact on system emissions is the same as building a new generator for the same purpose.
- **Existing generator is in a region with a very clean grid mix and restrictions on new fossil development and/or carbon emissions (acknowledged by Treasury).** If 45V hydrogen production load is added in a region with relatively little existing fossil generation and restrictions (such as state laws) that constrain new additions to clean generation only, then the incremental resources that join the system to serve load will be clean, regardless of whether those new resources are serving existing load and existing resources are serving hydrogen production, or vice-versa.
- **Existing generator qualifies to supply a state clean energy (or renewable) standard.** Most state renewable energy standards do not distinguish between existing and new renewable generators but rather simply require that loads acquire and then retire EACs from either generator type in sufficient quantity to meet the standard. If EACs produced by an existing generator are not sold to loads for purposes of meeting the standard but are instead sold to a hydrogen producer for 45V qualification purposes, the supply of renewable EACs available to meet the state standard will fall, which in turn will drive an increase in price for state EACs to whatever level is needed to induce incremental new entry, and new renewable generators will enter the market to replace the EACs sold to the hydrogen producer.

Conversely, 45V-linked EAC sales from a new zero-carbon generator may not result in a net additional new zero-carbon energy if:

- **New generator is in a region where demand for new renewables is high and supply is constrained.** In certain regions of the country there is significant demand for renewable EACs due to state renewable energy goals, but supply falls well short of demand due to limitations of the existing transmission system to support large volumes of new renewable entry, permitting constraints, and limitations of the ability of the Regional Transmission Operator ("RTO") to process new generator interconnection requests in the volume needed to meet demand. In such regions the rate of entry for new renewables is thus already at its maximum level with or without 45V. To the extent that new resources sell their EACs to hydrogen producers for 45V purposes, they will simply cannibalize supply that would have otherwise gone towards state clean energy programs. This will cause those programs to fall even further short of their goals, rather than resulting in additional net clean electricity entering the system that would not have entered absent 45V.
- **New generator is economic without 45V attribute sales.** If a new zero-carbon generator is economic without the additional revenue from EAC sales for 45V purposes, it will likely enter the market regardless of whether it is able to sell such EACs or not and regardless of whether additional hydrogen production demand is added to the system. Thus, allowing the generator to sell EACs for 45V does not in this case trigger a change in the amount of new zero-carbon electricity on the system – the electricity is added to the system with or without 45V.
- **New generator is built by a vertically integrated regulated utility to serve native load.** If a new zero-carbon generator is built as part of a regulated utility plan to serve its native load, it will generally receive a regulated price that covers its cost and return and thus will be built regardless of whether it has the opportunity to sell credits for 45V purposes. A sale of EACs for 45V purposes will simply lower the net cost of paying for the resource for native load customers of the regulated utility but will generally not affect whether or not the resource is built.

Real-world examples of these exceptions are widespread and prevalent in all regions of the country. At a high level, this can be seen by simply examining the current and projected near-term future of zero-carbon generation nationwide without consideration of the 45V credit. The U.S. Energy Information Administration's ("EIA") electric sector modeling in the 2023 Annual Energy Outlook explicitly does not include any representation of the 45V tax credit.[5] Despite excluding the hydrogen tax credit, EIA nonetheless projects that 424 gigawatts of new zero-emission capacity will be built between 2023 and 2030, which more than doubles the 403 gigawatts of existing zero-carbon capacity as of 2022.[6] All of this capacity, both new and existing, is projected to be built and/or remain in operation without any benefit from 45V-linked EAC sales and without any additional demand from electrolytic hydrogen production. Yet Treasury's proposed rule arbitrarily designates the 424 gigawatts of new capacity as fully incremental and the 403 gigawatts of existing capacity as not incremental, despite both types being built and operated without any benefit from 45V per EIA's analysis. A closer review of the policy fundamentals in different regions of the country underscores why the distinction drawn in the proposed rule is arbitrary as a matter of practical reality.

Treasury's proposed incrementality rules are inconsistent with electricity market dynamics in all regions of the country

With respect to how the market and policy fundamentals intersect with the proposed 45V Incrementality rules, states can generally be classified in four groups:

Group 1: *Competitive markets with high demand for EACs*

The PJM and ISO-New England Regional Transmission Organizations operate power markets that cover much of the Mid-Atlantic, parts of the Midwest, and New England region.

FIGURE 1: GROUP 1 STATES

Source: Federal Energy Regulatory Commission, Electric Power Markets (updated May 16, 2023), https://www.ferc.gov/electric-power-markets.

Together these markets account for about 20% of total national zero-carbon generation that EIA projects by 2030.[7] In both markets, generation is mostly built by independent power producers under a competitive market model to

[5] U.S. Energy Information Administration, *Annual Energy Outlook 2023*, March 16, 2023, Appendix Table 1. ("AEO")

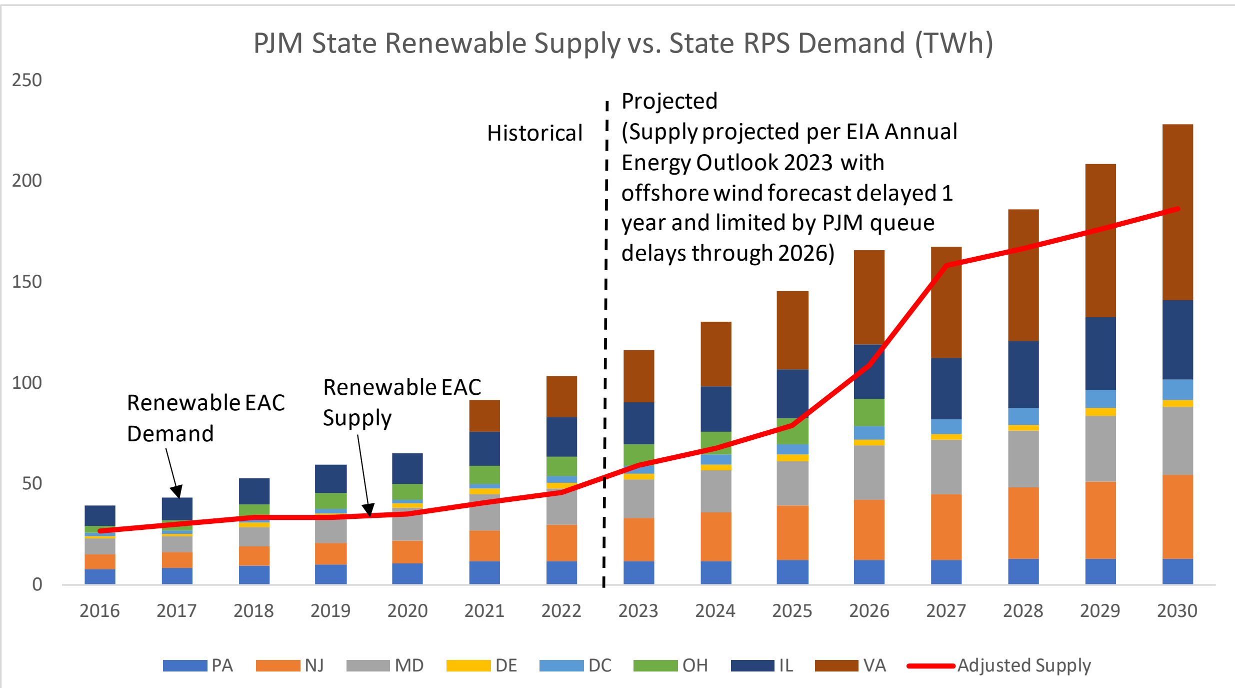
[6] AEO, Supplemental Reference Case Table 56.

[7] *Id.*

serve the broad interconnected regional power markets covering each. In both regions, there is substantial present and future demand for renewable EACs that is broadly driven by state Renewable Energy Standards ("RESs") that well outstrips the available supply. The presence of this substantial EAC demand that is independent of and additional to potential zero-emission EAC demand driven by 45V hydrogen production, and the fact that present demand outstrips supply, means that in these regions the use of new clean generation to serve hydrogen production will result in the same "induced emissions" as the use of existing generation to serve hydrogen production.

Using PJM as an example, Figure 2 below shows the state RES demand for renewable EACs relative to supply in the region, both for recent history and projected through 2030 using the 2023 Annual Energy Outlook from the U.S. Energy Administration.

FIGURE 2



Source: EIA Electric Power Annual (state level load and renewable generation). EIA Annual Energy Outlook 2023. Database on State Incentives for Renewables (DSIRE) from the NC Clean Energy Technology Center at North Carolina State University. Totals do not include states with only a small fraction of load within the PJM region (IN, MI, KY, NC) and assume that 70% of Illinois demand and renewable production is located within PJM.

This demand is driven by state RESs throughout the region, which require end-users to surrender renewable EACs (a.k.a. "Renewable Energy Credits" or "RECs") equal to an increasing fraction of load over time. Importantly, in almost all cases state RES programs do not distinguish between new and existing generators[8] and allow both types of generators to sell EACs for compliance purposes without any generator vintage[9] or incrementality provisions of

[8] In some cases, state RESs do impose a vintage requirement that only qualifies renewables that have come online after the inception of the state RES, which is typically in the late 1990s or early 2000s, depending on the specific state. For practical purposes these vintage constraints do not impact the economics discussed here.

[9] RES rules typically require that electricity associated with EACs utilized for compliance be produced within 1-2 years of the customer's consumption of electricity, but there are no such RES requirement associated with the initial date of generator commercial operation.

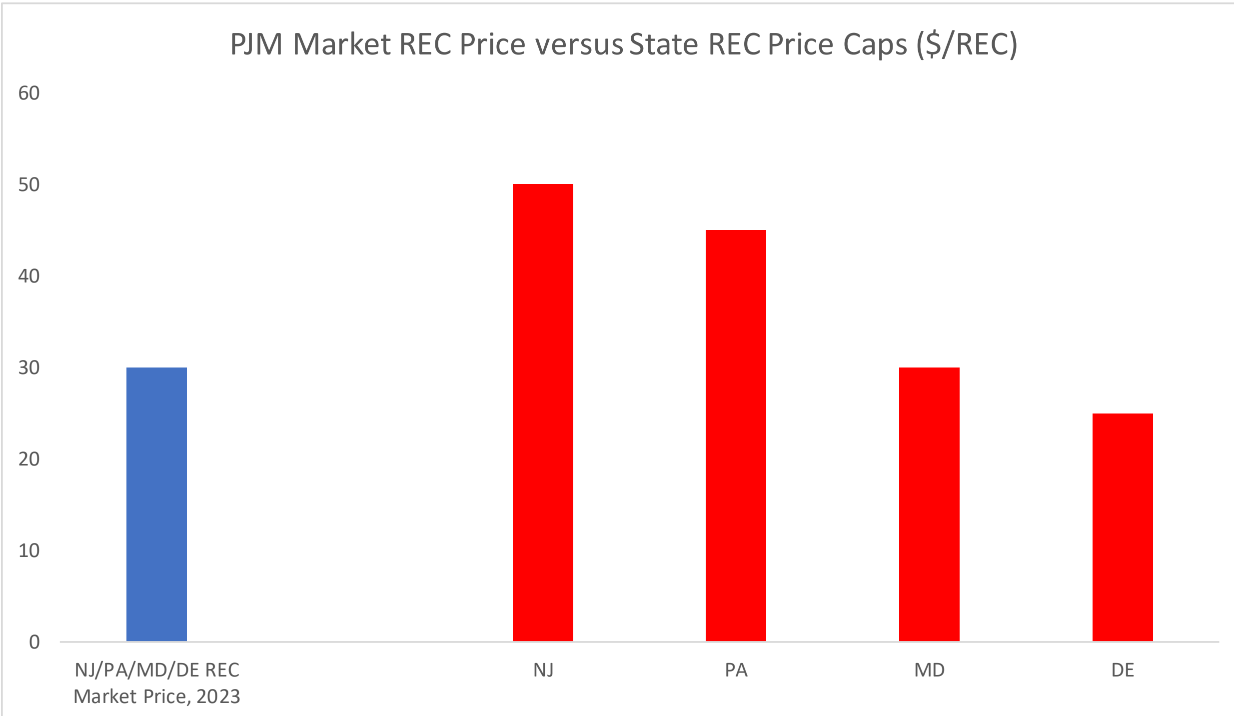
the kind that Treasury proposes for the 45V rules. PJM state RESs generally allow electricity consumers within the state to source renewable EACs from across the entire PJM footprint for compliance purposes, and there is a liquid market for renewable EACs that can qualify for multiple similar state programs within the region. Thus, it is appropriate to consider aggregate supply and demand for renewable EACs across the entire PJM RTO as effectively a single market.

In the aggregate across the region the supply of renewable EACs in PJM has been short of demand since at least 2016, and as of 2022 available supply is only able to serve about half of demand even before any consideration of potential additional demand arising from hydrogen production driven by 45V. There are several reasons for this shortfall: 1) renewable resource quality is patchy across the PJM footprint and transmission is not always sufficient to allow renewables to interconnect and deliver electricity, 2) siting and permitting can be challenging in many localities, and 3) PJM's queue for studying and authorizing interconnection has been unable to keep up with the volume of new projects seeking to connect to the system to satisfy demand for renewable EACs, which ultimately culminated in a two-year freeze on queue requests and implementation of a new process that has resulted in multi-year delays for most renewable projects in the pipeline.[10] Taken together, these practical constraints mean that it has been impossible to fully supply demand for renewables across PJM regardless of economics.

The result of this imbalance of supply and demand is that the price of renewable EACs has risen to the point where it exceeds the willingness-to-pay of many states and consumers, and demand simply goes unmet as a result. Figure 2 shows the recent price of PJM Renewable Energy Credits, compared to the Alternative Compliance Payment values for select PJM states (which mechanically form the upper bound on willingness-to-pay for renewable EACs to satisfy that state's standards). If the renewable EAC price is close to or above the Alternative Compliance Payment values, electricity consumers will simply pay that amount to the state to comply, rather than pay a higher price for renewable EACs.

[10] *See* 181 FERC ¶ 61, 162 (2022).

FIGURE 3



Source: Lawrence Berkeley National Laboratory (Galen Barbose), *U.S State Renewable Portfolio & Clean Electricity Standards: 2023 Status Update*, June 2023, at 34 (REC price estimated from graphic). https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf. More recent REC prices observed in over-the-counter markets are at similar levels.

As Figure 3 shows, the market price of renewable EACs in PJM exceeds state program alternative compliance payments in both Maryland and Delaware, and other states such as Illinois and Virginia have more complex mechanisms in place that limit demand as the cost of renewable resources rise, leading to an outcome where demand for renewables from state programs simply goes unmet because there are not enough renewable EACs to go around.

As Figure 2 shows, this shortfall is likely to persist for some time. The constraints associated with PJM's interconnection queue are likely to remain significant through at least 2026. The projections in the EIA's Annual Energy Outlook suggest that supply may start to catch up to demand in the latter part of the 2020s, but nonetheless will still fall short of aggregate demand even by 2030. While it is plausible that supply and demand may eventually come into balance at some point in the 2030s, this will require that PJM and stakeholders solve the practical constraints that have limited deployment below the level needed to meet demand in the past; if those constraints remain significant, it is also quite plausible that the shortfall may persist indefinitely.

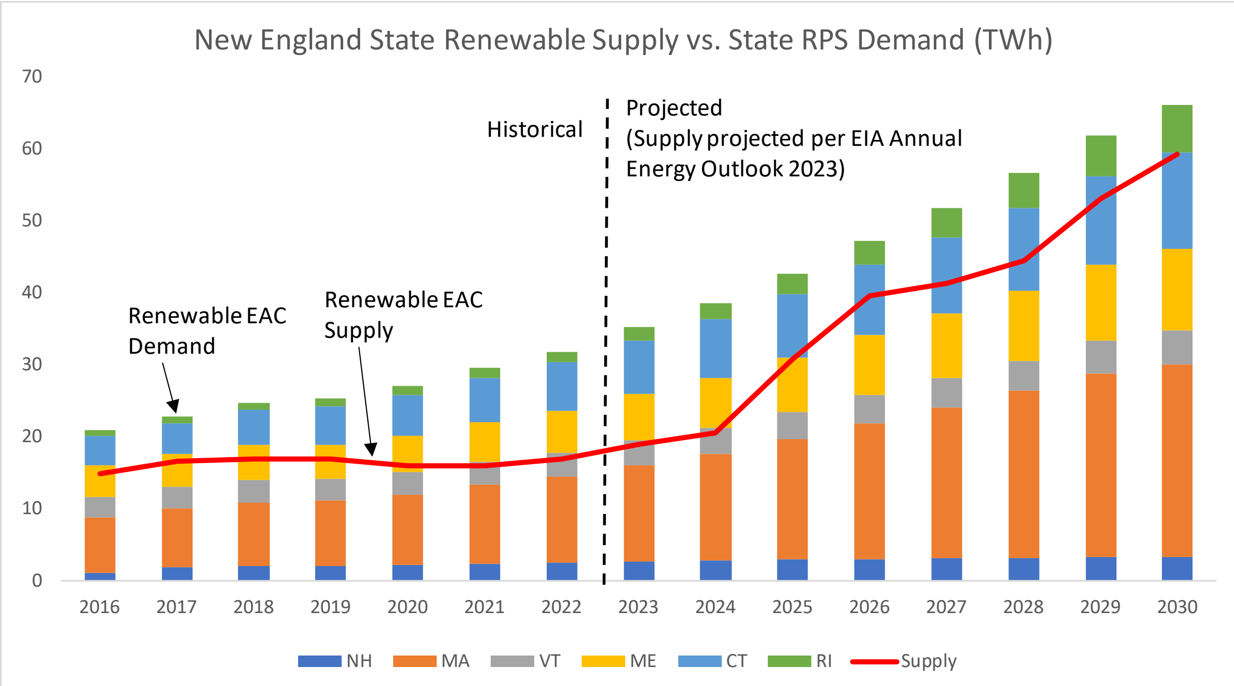
From the perspective of the 45V rules on incrementality, under the current fundamentals in PJM – the largest electricity market in the country – there is no meaningful difference between supplying a hydrogen project with zero-carbon EACs from either an existing or new generator with respect to the impact of the sale on system-wide emissions. If a new resource in PJM comes online in the next several years and sells its EACs to a hydrogen producer for 45V purposes, the total amount of renewable resources coming online will not change at all relative to a but-for world where that resource instead sells its EACs to an entity seeking to comply with state RPS programs. In either case the total supply of new renewable generation is already maxed out and well short of demand with or without 45V because new renewable entry is limited by practical non-economic constraints such as PJM queue process. Given the high demand for renewables and high EAC prices, if more renewables could come online, they would do so with or without 45V, but they cannot actually do so for the practical reasons discussed above. Thus, the only effect of a 45V-driven EAC sale is to cannibalize renewable EAC supply that would otherwise be utilized for state RPS programs, further driving up REC prices and forcing additional non-compliance with the state standards. The amount of physical new build renewable capacity will be the same either way. The sale of EACs from an existing renewable generator for 45V purposes has the same effect – the total amount of new renewables that are built is unchanged, but EAC supply that would otherwise be utilized by state programs is removed, causing a larger shortfall relative to state targets. Thus, under the environment currently prevailing in PJM, there is effectively no distinction between selling 45V-linked EACs from either new and existing resources with respect to their emissions impact and their impact on the overall amount of zero-carbon electricity. Under these conditions neither type of renewable generator is incremental. Indeed, the only truly incremental clean resources under these market conditions are nuclear units that, but for the ability to sell EACs to 45V-eligible hydrogen producers, would otherwise retire.

Even if the supply-side constraints that currently limit renewable new entry eventually ease, there will continue to be little or no effective difference between new and existing renewable resources in PJM in terms of their induced emissions, although the reasons for this result will change. To the extent that a hydrogen producer enters the market and buys renewable EACs from a new renewable generator, if renewable entry is unconstrained that will result in the direct addition of new zero-carbon electricity to the system in the form of the resource itself and thus the resource is incremental per Treasury's framework. However, a sale of renewable EACs from an existing renewable generator to the hydrogen producer will have the same impact, albeit indirectly. Because renewable EAC demand for state RPS programs is both substantial and does not distinguish between EACs from existing and new renewable generators, a sale of EACs for non-RPS purposes, such as for 45V compliance, would result in a reduction of EAC supply available for state RPS compliance. The only way to fully serve demand for state RPS programs will be to build new renewable generation to fill the shortfall created by the existing-resource EAC sale for 45V purposes. Thus, the net supply of zero-carbon electricity on the system will increase by the amount of the sale due to induced entry by another resource to serve state RES demand, and the overall impact on the amount of zero-carbon electricity on the system and overall system emissions is the same regardless of whether the 45V-related EAC sale comes from existing or new renewable resources.[11]

These fundamental economics similarly prevail in New England, which like PJM is a multi-state power market administered by a Regional Transmission Organization (ISO New England). Figure 3 shows historical and projected aggregate demand for renewable EACs across the New England states:

[11]If the state RPS market were significantly oversupplied (which, given the history is unlikely), EACs in the region would likely be economically viable with or without the additional revenue provided by EAC sales for 45V purposes and thus would not be incremental.

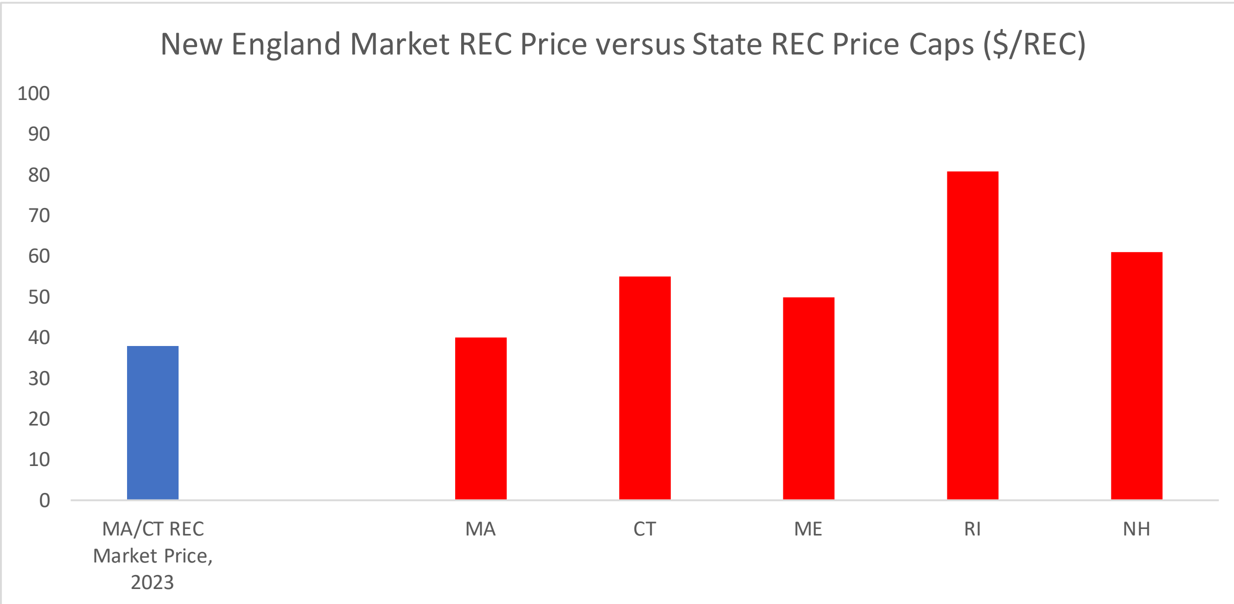
FIGURE 4



Source: EIA Electric Power Annual (state level load and renewable generation). EIA Annual Energy Outlook 2023. Database on State Incentives for Renewables (DSIRE) from the NC Clean Energy Technology Center at North Carolina State University

Similar to PJM, renewable development in New England has historically been constrained by challenges with siting and permitting, availability of transmission, and patchy resource distribution. The result is that renewable additions have failed to keep pace with increasing state standards, which has resulted in very high renewable EAC prices that roughly equal the price cap embedded in the largest state program (Massachusetts), as figure 4 below demonstrates:

FIGURE 5



Source: Lawrence Berkeley National Laboratory (Galen Barbose), *U.S State Renewable Portfolio & Clean Electricity Standards: 2023 Status Update*, June 2023, at 34 (REC price estimated from graphic). https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf. More recent REC prices observed in over-the-counter markets are at similar levels.

As a result, similar economics prevail in New England as do in PJM: in the near-term the supply of renewables is effectively fixed and maxed-out, so there is no effective difference between new and existing resources with respect to their induced emissions. And in the longer run the presence of substantial state RPS demand that does not distinguish between new and existing renewable generators effectively results in EAC sales for hydrogen production will result in both new and existing resources being incremental.

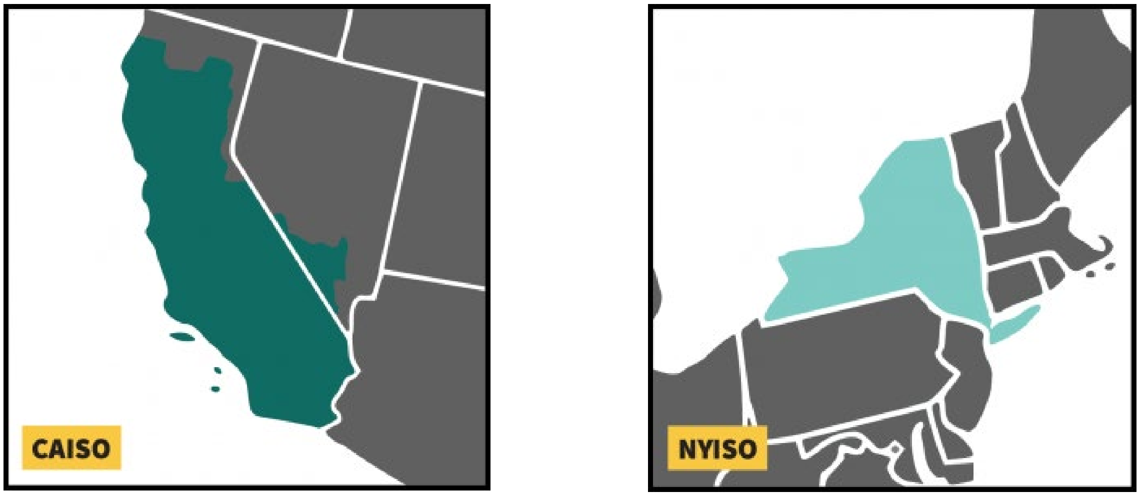
As the foregoing discussion makes clear, the actual, real-world situation in both the PJM and New England regions clearly shows that Treasury's proposed binary rules on incrementality are arbitrary. Currently, most new renewables are not incremental at all.

Group 2: *Single-market states with enforceable net-zero goals*

The states of California and New York, which together account for about 7% of total projected national zero-carbon generation by 2030,[12] are single-state power markets that each have aggressive, enforceable legislative goals that target net zero statewide emissions by 2045 (California) or 2050 (New York) and a fully decarbonized electric sector by 2040 (New York) or 2045 (California).

[12] AEO, Supplemental Reference Case Table 56.

FIGURE 6: GROUP 2 STATES



Source: See Figure 1.

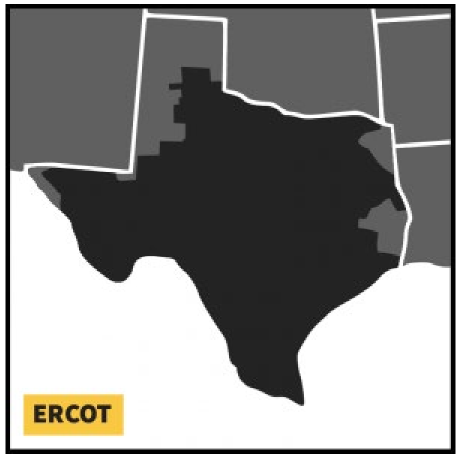
As Treasury has acknowledged in asking for comments, in these states the addition of hydrogen production load cannot result in the construction of new fossil generation facilities by law and is unlikely to result in significant incremental emissions from existing fossil generators because such generators are being rapidly phased out. The result is that as long as a hydrogen producer in those states purchases zero-carbon EACs from a zero-carbon generator of any type – new or existing – the impact on incremental systemwide carbon emissions will be similar and either zero or close to zero because the hydrogen producer is not sustaining the operation of a emitting generator, and the incremental electricity that physically enters the system to supply the new load will by force of state policy be zero-emission. Thus, both new and existing zero-carbon resources should be considered incremental in these states.

A similar dynamic exists in other states that are part of larger multi-state power markets, including Illinois, Washington, Michigan, Massachusetts, Maryland, Virginia, and Rhode Island, each of which has similarly aggressive climate goals. That these states are part of a larger power market may complicate the analysis, but ultimately the impact of clean energy policies in those states will result in both new and existing generation being largely incremental. While Treasury has asked for comment on the possibility of an exception for generation in such states, it has not included such an exception in its proposed rules and has not indicated how such exceptions might be adjudicated.

Group 3: ***States with competitive markets where renewable units are economic (Texas)***

The ERCOT region, which comprises most of Texas, has seen substantial and ongoing renewable generation development by independent power producers for the past decade despite minimal state support.

FIGURE 7: GROUP 3 STATES



Source: See Figure 1.

As of 2023 about 58 gigawatts of renewables have been built to date in ERCOT (compared to a peak load of about 80 gigawatts), mostly by independent power producers, with a further 30 gigawatts expected to be built by 2030.[13] This rapid entry has been supported almost entirely by electricity market prices and federal tax credits, with minimal state support and very low prices for zero-emission EACs. This suggests that renewable new entry in ERCOT has been and will continue to be economically viable with or without the additional revenue provided by EAC sales for 45V purposes and thus that most of the new renewables in Texas are not actually incremental from the perspective of Treasury's proposed rules. ERCOT accounts for about 10% of total projected national zero-carbon generation by 2030.[14]

Group 4: *States with vertically integrated regulated utilities*

The U.S. Energy Information Administration projects that about 63% of total national zero carbon generation by 2030 will be located in areas of the country where most generation is built and owned (or contracted for) by traditional vertically integrated regulated utilities that recover the cost of their generation portfolios through cost-based regulated rates and build generation to serve captive native load. [15] These areas include the Southeast, the Great Plains, much of the Midwest, and the West outside of California.

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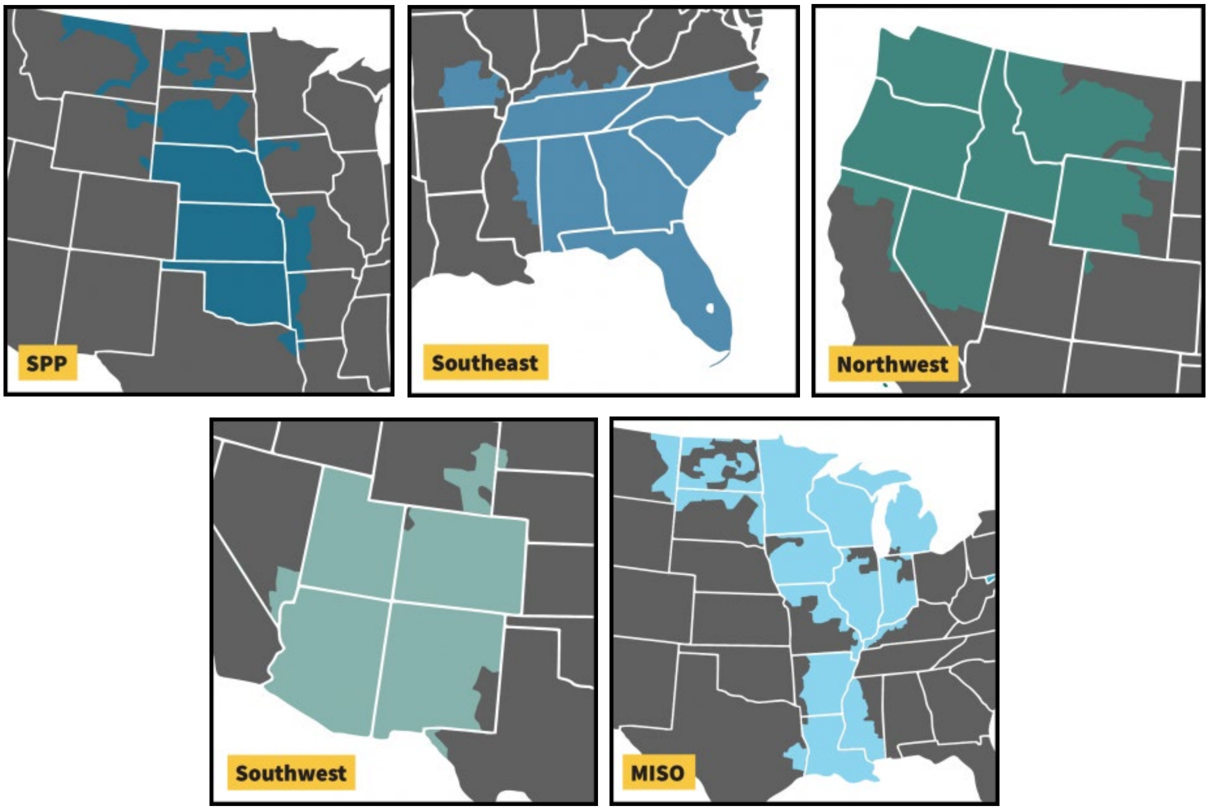
[13] AEO, Supplemental Reference Case Table 56.

[14] *Id.*

[15] *Id.*

FIGURE 8: GROUP 4 STATES



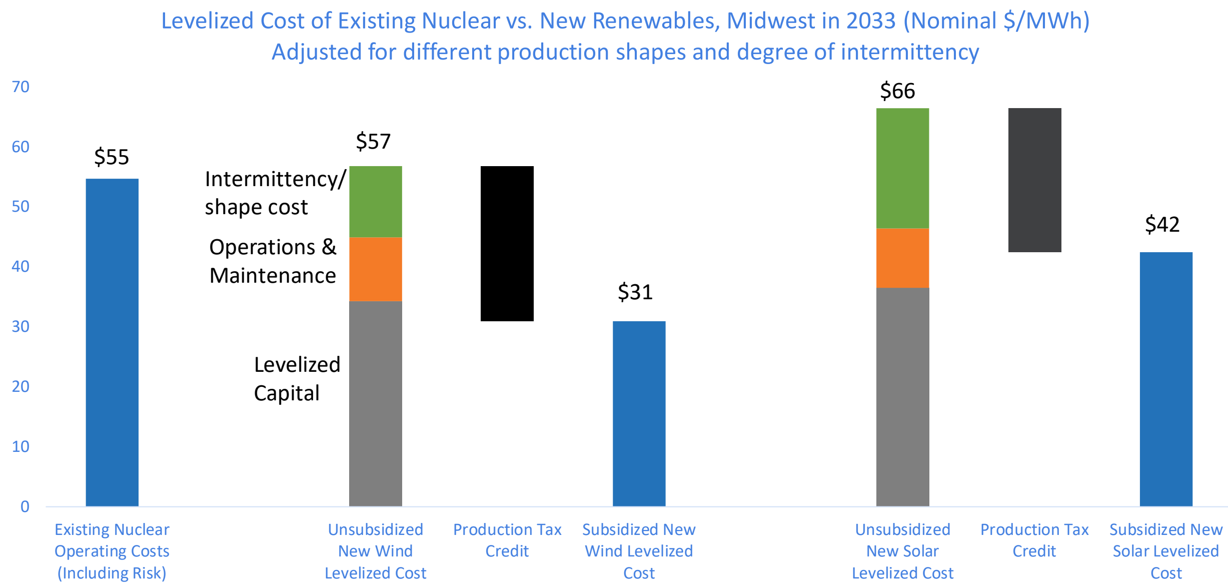
Source: See Figure 1.

Most zero-carbon generation that is built under the traditional cost-based rate regulation model is not incremental because the economics and decision process surrounding new builds are largely independent of whether or not the generation may sell 45V-linked EACs and most of it will get built either way. In most regulated states, a new zero-carbon generator built by the regulated utility to supply native load will not have any particular market for or requirement to retire its associated EACs, and thus could simply sell the EACs to a hydrogen producer as an additional revenue stream that would be credited back to customers (or the utilities' shareholders). But the generator in this example is not incremental; physically it would be built with or without 45V. While it is plausible that zero-emission generation could potentially be incremental in regulated regions if it were purpose-built to physically supply electricity and EACs to a hydrogen producer, the proposed rules do not distinguish between this type of generation and the more common instance where generation is simply built to supply the utility's own customers and then the utility sells EACs as a separate revenue stream, nor would distinguishing between and adjudicating between these types of situations be straightforward or easily administrable.

Existing nuclear generation in all regions is more likely to be incremental than new renewables from 2033 onward

Across all regions, the tax credits and other incentives in the Inflation Reduction Act outside of 45V are likely to be a key determinant of whether a given generator is incremental or not, rather than whether a resource is newly constructed or not. This dynamic is particularly important when evaluating the incrementality of existing nuclear resources. Relative to most types of other carbon-free generation, nuclear has high operating and capital reinvestment costs, and operators take considerable market and operational risk when committing to operate a nuclear facility. As a result, without state or federal support, existing nuclear facilities have in the past experienced economic challenges leading to retirements. These challenges were temporarily relieved by the IRA, which instituted a production tax credit for existing nuclear that, in conjunction with market revenues, provides a nuclear resource with a floor on expected total revenues of approximately $44 per megawatt-hour in 2024, which then increases at inflation to an expected level of approximately $54 per megawatt-hour in 2032. This floor price is broadly intended to provide sufficient revenue to cover the ongoing costs, capital, and risks of owning and operating an existing nuclear generator. However, from 2033 onward the nuclear credit expires. New renewables, by contrast, benefit from a technology-neutral production (or investment) tax credit that will continue well past 2033. Thus, from 2033 onward, existing nuclear is considerably less economic than new renewables, even after considering nuclear's more favorable firm all-hours production profile relative to the less favorable intermittent production profiles of wind and solar.

FIGURE 9



Source: Nuclear cost based on nuclear PTC phase out cost of $43.75/MWh in 2024 escalated at inflation of 2.5% to 2033. Wind/solar costs based on NREL 2023 Annual Technology Baseline for 2033 entry of category 7 wind and solar using the moderate cost scenario. Intermittency/shape costs estimated by calculating the difference between the nuclear and renewable Levelized Avoided Cost of Energy as reported in the Energy Information Administration Levelized Costs of New Generation in the Annual Energy Outlook 2023 (https://www.eia.gov/outlooks/aeo/electricity_generation/)

As Figure 9 shows, while existing nuclear is a more economic source of zero-carbon electricity than new renewables on an unsubsidized basis, starting in 2033 with the expiration of the nuclear production tax credit, nuclear will be considerably less economic than new renewables once subsidies are considered, with operating costs for nuclear at $55 per megawatt-hour versus $30 to $40 per megawatt-hour for new renewables.

These economics strongly suggest that from 2033 onward, existing nuclear, rather than new renewables, will be the marginal source of zero-carbon electricity. With the benefit of tax credits, new renewables are likely to be economic with or without the hydrogen PTC, but existing nuclear will likely be economically challenged absent the ability to sell EACs for 45V qualification purposes because the willingness-to-pay by stakeholders for zero-carbon electricity will be primarily driven by renewable economics. Thus, existing nuclear is much more likely to be incremental than new renewables in the long-term. Treasury's proposed rules do not recognize this dynamic but rather, as discussed previously, treat new renewables as fully incremental and existing nuclear as not incremental at all.

Treasury's oversimplified proposed rule does not correspond to reality

Taken together, this survey of the national electric sector with respect to the proposed incrementality provisions of the 45V rule demonstrates that significant exceptions to the binary distinction between new and existing generation exist for zero-carbon generation in every region of the country and for all types of zero-emission generation. It is quite plausible that well over half of existing and potential new entrant zero-carbon generation faces economics that run counter to Treasury's oversimplified assumption that new generation is fully incremental and existing generation is never incremental. Further, as the discussion above reveals, in many cases the determination of incrementality may be quite complex and may not be fully binary. For example, the ability to sell 45V-linked credits may reduce the risk of retirement for many existing resources over time, but it will not always flip the probability of retirement from 100% to zero. Similarly, whether a given resource meets the definition of incremental can change over time as market fundamentals change. And finally, as the discussion of existing nuclear generation demonstrates, differing operational economics and levels of government support can greatly affect whether a particular resource is incremental or not, and can easily lead to existing generation being more likely to be incremental than new generation. Given the uncertainties and complexities involved in determining whether a specific zero-carbon generator is incremental or not, and further given the fact that these uncertainties generally apply in roughly equal measure to both new and existing resources, Treasury's highly asymmetric treatment of new and existing resources is arbitrary.