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February 26, 2024

via regulations.gov

Docket ID No: IRS-2023-0066

The Honorable Lily Batchelder
Assistant Secretary (Tax Policy)
Department of the Treasury
1500 Pennsylvania Avenue, NW
Washington, DC 20220

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Re: Proposed Treasury Regulations on Section 45V Credit for Production of Clean Hydrogen (REG-117631-23)[1]

Dear Ms. Batchelder and Mr. Paul,

Calpine Corporation submits these comments to the Department of the Treasury ("Treasury") and the Internal Revenue Service ("IRS") regarding the proposed regulations for Sections 45V and 48(a)(15) of the Inflation Reduction Act ("IRA").[2] In response to a prior request for comments, Calpine explained why electricity generated by a natural gas-fired power plant newly equipped with carbon capture and storage ("CCS") should qualify as "incremental" clean generation for the Section 45V credit for production of hydrogen. We explained that use of this newly minimal-emitting electricity to power an electrolyzer would have no "significant indirect" emissions because the load served by that gas plant before it installed CCS would now be served by another gas plant without CCS and with a similar emissions rate.[3]

This comment provides data and modeling showing that use of electricity from a newly CCS-

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[1] 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).

[2] Pub. L. No. 117-169, 136 Stat. 1818 (August 16, 2022).

[3] Calpine Corp., Supplemental Comment on Credits for Clean Hydrogen Under Section 45V, at 5 (Sept. 28, 2023), IRS-2022-0029-0244.

equipped gas-fired power plant to power an electrolyzer will not increase systemwide emissions. Specifically, Aurora Energy Research modeled the emissions effects when the electricity from a CCS-equipped natural gas-fired combined-cycle ("NGCC") plant within the Electric Reliability Council of Texas ("ERCOT") is used to power an electrolyzer over the period of 2027–38. Calpine only modeled an example in ERCOT due to time constraints. The results demonstrate that a CCS-equipped NGCC is a new source of minimal-emitting generation that does not cause induced grid emissions. Accordingly, Treasury and IRS should deem energy attribute certificates ("EACs") associated with electricity generated by a newly CCS-equipped gas-fired power plant to be "incremental." Calpine believes these results should logically apply in regions other than ERCOT, especially those with lower renewable penetration rates. However, to the extent that Treasury and IRS identify particular circumstances and regions other than ERCOT where the potential for induced grid emissions precludes an ex-ante determination that EACs from a CCS-retrofitted NGCC facility are incremental, they should provide a streamlined process for DOE to approve a source- and region-specific determination based on modeling similar to that provided herein.

I. Background on Calpine

Calpine operates the largest fleet of NGCC and cogeneration – or combined heat and power ("CHP") – facilities in the United States.[4] Calpine is also the nation's largest producer of renewable geothermal electricity. Together, its generation resources are capable of delivering approximately 26,000 megawatts ("MW") of clean, reliable electricity to customers and communities in 19 U.S. states and Canada, with more than 76 power plants in operation and one under construction. Calpine also operates and is developing battery storage projects, with 80 MW in operation and 1,500 MW in development.

Calpine is a major innovator in piloting the use of carbon capture, utilization and storage ("CCUS") to achieve reductions in emissions from NGCC and CHP facilities. Calpine has two CCUS pilot projects underway at Los Medanos Energy Center, a CHP facility in Pittsburg, California, one of which demonstrates a technology expected to capture as much as 95% of the CO2 emissions from a gas-fired power plant.[5] We are also completing multiple Front-End Engineering Design ("FEED") studies for implementation of CCUS, including one at Delta Energy Center, an NGCC facility in Pittsburg, California, and another at Deer Park Energy Center, a CHP plant in Deer Park,

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[4] Except where necessary to refer to a particular facility or to distinguish between NGCC and CHP facilities, all references to an "NGCC" facility within these comments are intended to refer to either an NGCC or CHP facility.

[5] *See* Judith Prieve, *First-of-its Kind East Bay Pilot Project to Capture Harmful Emissions Could Be Game-Changer for Gas-Powered Plants*, SAN JOSE MERCURY NEWS (Jul. 15, 2023), https://www.mercurynews.com/2023/07/15/calpine-unveils-pilot-project-to-produce-cleaner-electricity-capture-harmful-emissions/ (describing Calpine's unveiling of a $25 million pilot project to capture as much as 95% of CO2 emissions from a gas-fired power plant); *Calpine & Blue Planet Transform Captured Carbon Into Limestone*, CARBON CAPTURE MAGAZINE (Sept. 28, 2022), https://carboncapturemagazine.com/articles/365/calpine-blue-planet-transform-captured-carbon-into-limestone (describing Calpine's partnership with Blue Planet, which combines captured carbon with calcium from waste to create a lightweight building material).

Texas.[6] In implementing the Carbon Capture Demonstration Projects under the Infrastructure Investment and Jobs Act, DOE's Office of Clean Energy Demonstrations recently announced more than $540 million in funding for two of Calpine's CCUS projects.[7] Baytown Carbon Capture and Storage Project will capture up to 2 million metric tons of CO2 each year from our CHP plant in Baytown, Texas and sequester it in saline storage sites on the Gulf Coast. Sutter Decarbonization Project will capture 1.75 million metric tons of CO2 each year from Sutter Energy Center in Yuba City, California and deploy a novel air-cooling system to minimize water usage—a critical innovation in the arid western United States.[8]

Calpine has long supported efforts to address climate change and reduce greenhouse gas ("GHG") emissions, including those from the power sector. Calpine also supports the IRS and Treasury's efforts to promote efficiency, certainty, and clarity for taxpayers in the electricity sector and investment community to deliver the environmental and economic benefits promised by the IRA.

II. Incrementality of Electricity From CCS-Equipped Plants

A. Treasury and IRS' Proposed Incrementality Requirement

Section 45V provides tax credits for production of "qualified clean hydrogen," with the value of the credit turning on the "lifecycle greenhouse gas emissions rate" of the "process" through which the hydrogen is produced.[9] "Lifecycle greenhouse gas emissions" are defined with reference to emissions produced through the point of production "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, or a successor model (as determined by the Secretary)."[10]

Because operating an electrolyzer is electricity-intensive, most of the lifecycle GHG emissions from electrolytic hydrogen are likely to come from electricity generation. In designing the regulations, Treasury and IRS are considering both the "direct" GHG emissions from generating the electricity as well as "significant indirect" emissions that result from use of that electricity.

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[6] *Funding Opportunity Announcement 2515, Carbon Capture R&D for Natural Gas and Industrial Point Sources, and Front-End Engineering Design Studies for Carbon Capture Systems at Industrial Facilities and Natural Gas Plants*, DOE Office of Fossil Energy and Carbon Management (Oct. 6, 2021), https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.

[7] *OCED Selects Three Projects in CA, ND, and TX to Reduce Harmful Carbon Pollution, Create New Economic Opportunities, and Advance Carbon Reducing Technologies*, DOE Office of Clean Energy Demonstrations (Dec. 14, 2023), https://www.energy.gov/oced/articles/oced-selects-three-projects-ca-nd-and-tx-reduce-harmful-carbon-pollution-create-new.

[8] https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations

[9] 26 U.S.C. § 45V(c)(2)(A) (emphasis added)

[10] *Id.* § 45V(c)(1)(A), (B).

The agencies propose that "significant indirect" emissions should include "induced grid emissions"—i.e., emissions that occur because existing clean electricity is diverted from the grid and replaced by electricity generated by higher-emitting sources. According to Treasury and IRS, these "induced grid emissions are an anticipated real-world result of electrolytic hydrogen production that must be considered in lifecycle GHG analyses."[11]

For example, when electricity generated by an existing 100 MW wind farm is diverted from deliveries to existing load (i.e., demand for electricity) to power an electrolyzer, the direct emissions of the electricity produced by those windmills is essentially zero. But it will cause *induced grid emissions* because the load previously served by that wind farm must now be served by the next resource in the dispatch queue on that grid. In most regions and at most times of the day and year, the next resource in the queue is a fossil fuel-fired plant. Therefore, use of these 100 MW of wind electricity to power an electrolyzer would result in zero direct emissions but induced grid emissions approximately equivalent to those associated with 100 MW of fossil generation. Diverting the generation from this existing zero-carbon resource to an electrolyzer therefore induces a significant increase in systemwide emissions.

However, because determination of induced GHG emissions requires "sophisticated power-sector models . . . [that] are complex and require many important input assumptions," DOE has stated that it is "not currently a practical, primary solution for lifecycle GHG assessment within 45VH2-GREET."[12] As induced grid emissions are not included in the GREET model, Treasury and IRS propose that clean electricity used to produce hydrogen must satisfy an "incrementality" requirement. Under the proposed rule, the clean electricity used to produce hydrogen must come from a generating facility with a commercial operations date ("COD") of not more than 36 months before the hydrogen production facility was placed in service.[13] Treasury and IRS would be able to track compliance because taxpayers would have to retire a qualifying energy attribute certificate ("EAC") for each unit of electricity claimed from a given source, and that EAC would list (among other things) the facility, its technology and feedstock, the COD of the facility, and the time the electricity was generated.[14]

As DOE explained in a recent white paper concerning Section 45V, "an existing fossil-fuel power plant that has recently added carbon capture and storage . . . could potentially also be considered incremental (and low-GHG, if its capture rate is sufficiently high), because it is a new source of

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[11] 88 Fed. Reg. at 89,228.

[12] Dep't of Energy, ASSESSING LIFECYCLE GREENHOUSE GAS EMISSIONS ASSOCIATED WITH ELECTRICITY USE FOR THE SECTION 45V CLEAN HYDROGEN PRODUCTION TAX CREDIT 12, https://www.energy.gov/sites/default/files/2023-12/Assessing_Lifecycle_Greenhouse_Gas_Emissions_Associated_with_Electricity_Use_for_the_Section_45V_Clean_Hydrogen_Production_Tax_Credit.pdf (hereinafter DOE WHITE PAPER).

[13] 26 CFR § 1.45V-4(d)(3)(i)(A), (d)(2)(i) (proposed).

[14] *Id.* § 1.45V-4(d)(1), (d)(2)(iii).

lower-GHG generation."[15] To ensure that use of electricity from newly retrofitted NGCC-CCS plants does not cause induced grid emissions and is properly eligible for the Section 45V credit, Treasury and IRS ask for comment on the following interrelated issues:

- Whether the electricity generated by such a facility should be considered incremental under circumstances such as if an existing fossil fuel electricity-generating facility after the addition of CCS (after upgrade), had a COD that is no more than 36 months before the relevant hydrogen production facility was placed in service.

- Whether, depending on its carbon dioxide capture rate, it would be appropriate to treat such a facility as a new source of minimal-emitting generation on the grid that would not be associated with induced grid emissions.

- What information would be needed to allow for qualifying EACs representing existing fossil fuel-powered electricity from facilities that have added CCS.

- Whether there are safeguards that can ensure that a hydrogen producer's purchase and use of electricity from an existing fossil fuel-fired electricity generating facility that installs CCS does not result in indirect GHG emissions due to the dynamics of the electricity market and electric grid.

- The direct and induced emissions impacts of making such a facility eligible, and whether and under what circumstances it would be appropriate to do so.[16]

B. Electricity from NGCC-CCS Plants Is Incremental

Prior to the issuance of these proposed regulations, Calpine explained in a comment that NGCC power plants that complete a CCS retrofit should be treated as a "new source of minimal-emitting generation on the grid that would not be associated with induced grid emissions." We first emphasized that it provides a new, clean supply of electricity that did not previously exist. We then explained that it does not cause significant indirect emissions:

> [T]he load that had previously been served by [a gas plant that just installed CCS] must be met by the next source in the dispatch queue. Critically, however, that existing load was previously served by a carbon-intensive resource: the gas plant *before* it was equipped with CCS. Once that generating resource is equipped with CCS and begins delivering low-carbon electricity to an electrolyzer, the next source in the dispatch queue that will be called upon to serve

[15] DOE WHITE PAPER, *supra*, at 10. The most recent version of the GREET model, which Argonne National Laboratory developed specifically for implementation of Section 45V, likewise allows users to designate an NGCC facility with CCS as the electricity source. Argonne Nat'l Lab., https://www.energy.gov/eere/greet (last accessed Feb. 23, 2024)

[16] 88 Fed. Reg. at 89,229.

> existing load will likely be another gas-fired plant *not* equipped with CCS. In other words, no "significant indirect" emissions occur as a result of diversion of electricity from load previously served by a gas-fired plant without CCS, to production of hydrogen in an electrolyzer.[17]

To address Treasury and IRS' request for comment, Calpine commissioned Aurora Energy Research to model the direct and indirect emissions in light of "the dynamics of the electricity market and electric grid." The results[18] demonstrate that systemwide emissions do not increase when the generation from an existing 500 MW NGCC facility newly equipped with CCS located within ERCOT is used to produce electrolytic hydrogen during the period 2027–38.

1. NGCC Facility

<u>Baseline:</u> To begin, it is necessary to determine baseline emissions in the absence of a new, clean supply from the CCS-abated plant. In Aurora's model results, if the NGCC facility does not undergo a CCS retrofit, it would emit a total of 12 million metric tons of CO2 from 2027–38. Meanwhile, baseline cumulative thermal generation in the system would be 2,832 terawatt-hours (TWh), resulting in cumulative emissions of 1,371 million metric tons of CO2. Additionally, the addition of electrolyzer load increases cumulative thermal generation by approximately 14 TWh for each 150 MW of electrolyzer load.[19]

<u>CCS-Retrofitted Plant</u>. We begin with two fundamental points about how a CCS-equipped NGCC plant would operate under foreseeable conditions:

- First, a CCS retrofit will in most cases result in a derating of the NGCC plant due to the electricity consumed by the CCS equipment. Accordingly, the facility previously rated at 500 MW would be rated at approximately 425 MW to the wholesale grid.

- Second, despite the downrating, the CCS-equipped plant would actually deliver *more* electricity to the grid than in the absence of the CCS retrofit. This is because the operator of a CCS-retrofitted NGCC facility will claim a Section 45Q credit, and, as a consequence, bid the facility into the market at a far lower price than in the absence of the CCS retrofit

[17] Calpine Corp., Supplemental Comments on Credits for Clean Hydrogen Under Section 45V and Clean Fuel Production Under Section 45Z, at 5 (Sep. 27, 2023), IRS-2022-0029-0244.

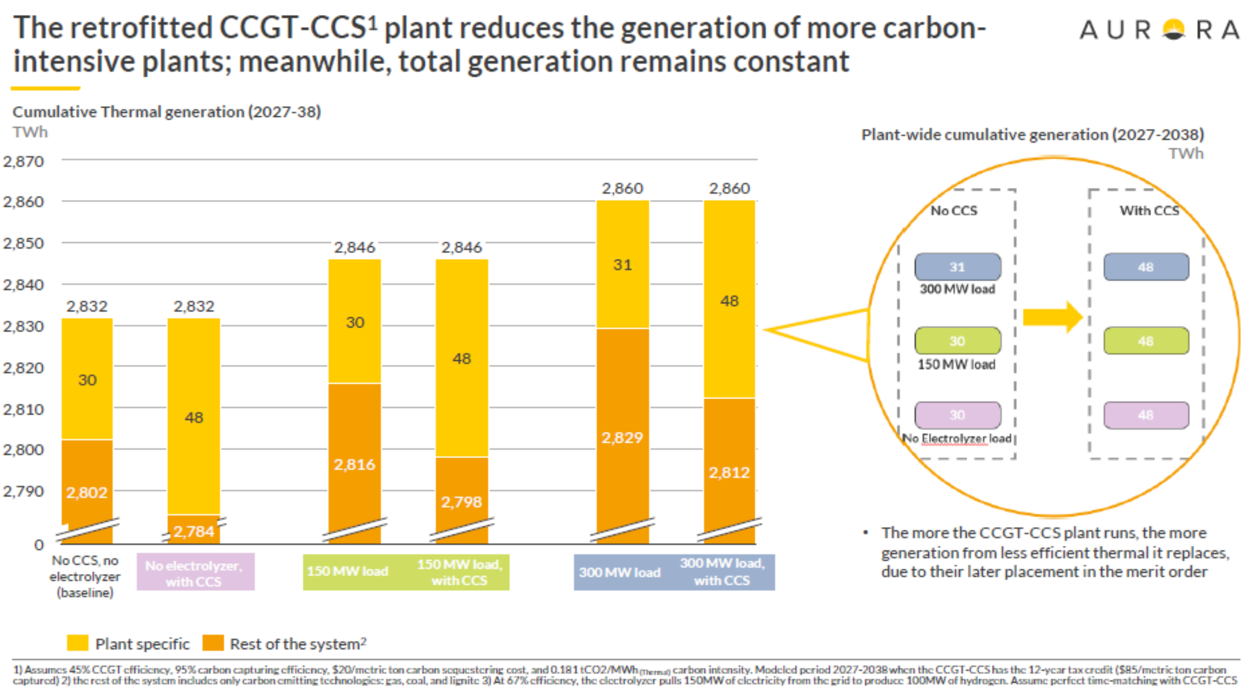
[18] Aurora Energy Research, "CCS Impacts to System Level Emissions for 45V IRS Comments" (Feb. 2024), Attachment, hereinafter, "Aurora Modeling Results."

[19] *Id*. at 14 (showing increase in cumulative thermal generation from 2027-2038 from 2,832 TWh in the baseline scenario to 2,846 and 2,860 TWh in the scenarios with addition of 150 and 300 MW of electrolyzer load and no CCS).

> because the marginal cost of each megawatt-hour (MWh) is significantly lower.[20] As a consequence, the plant will be dispatched more frequently, causing it to deliver even more electricity to the grid than in the absence of the CCS retrofit, and displacing the generation of other higher-emitting resources.

Aurora's model projects that, despite the derate of the facility, its total generation from 2027–38 *increases by 60%* relative to a baseline in which it does not undergo a retrofit.[21] The increase in dispatch for the CCS-retrofitted NGCC facility relative to a baseline without CCS is illustrated by **Figure 1** below, along with changes in facility-specific and cumulative thermal generation as increasing amounts of electrolyzer load are added to the grid.

Figure 1.



The impact the CCS retrofit has on plant-specific and systemwide emissions is significant. The system would include the same 2,832 TWh of thermal generation as in the baseline, while emitting *17.9 million tons less* of CO2 emissions—11 million tons less in direct emissions from the plant

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[20] *Id*. at 12. The marginal cost of each MWh is significantly lower because the 45Q credit is paid based on each ton of carbon oxide captured. Thus, the marginal cost of generating an additional MWh is the fuel cost (and other costs like variable operation and maintenance (O&M)), *less* the 45Q credit that will be received by capturing the carbon oxide associated with generating the next MWh. This is similar to how wind, solar, and nuclear production tax credits are observed to affect marginal cost-bidding in wholesale electricity markets.

[21] *Id*. at 14 (showing that plant-specific cumulative generation over the period increases from 30 or 31 TWh in the baseline scenario to 48 TWh after the CCS retrofit).

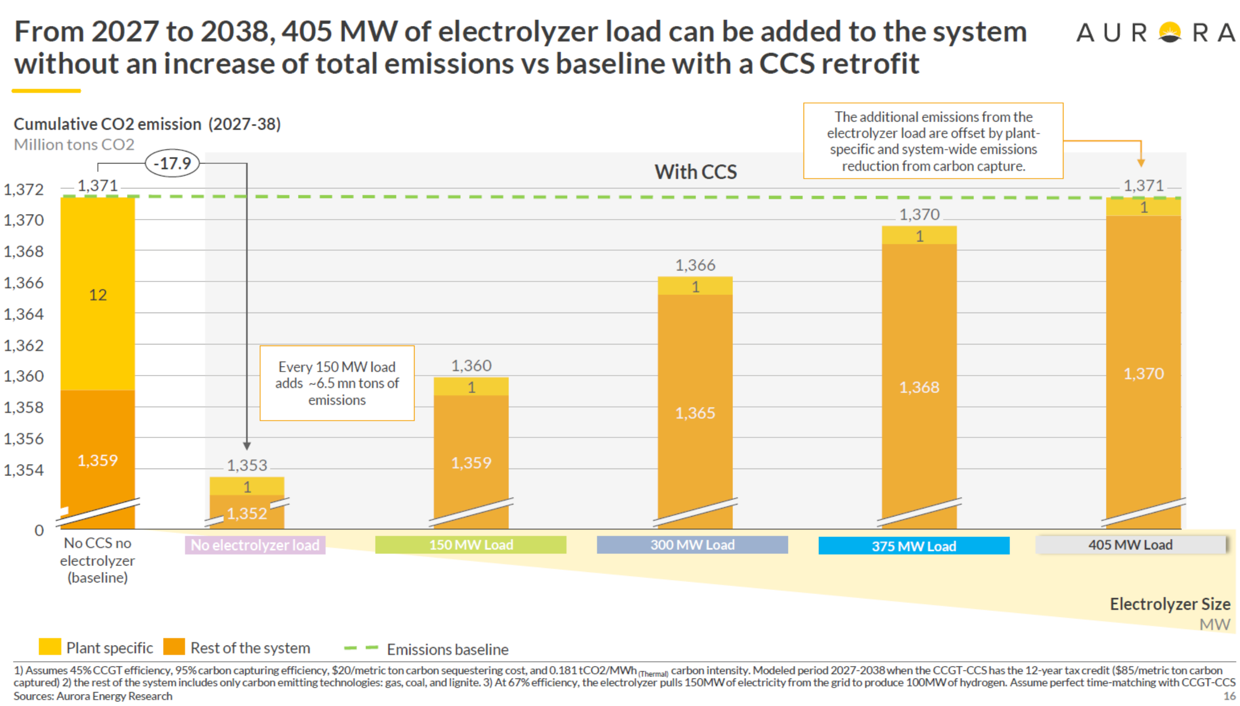
relative to the baseline in which it is not retrofit and 7 million tons less in indirect emissions.

- *Direct emission reductions:* After the plant is retrofitted with CCS, it newly generates minimal-emitting electricity. Accordingly, its total direct emissions over the study period are reduced from a baseline of 12 million metric tons of CO2, to 1 million metric tons, corresponding to a reduction of 11 million metric tons.[22]

- *Indirect emission reductions:* Because the CCS-equipped plant will be dispatched more frequently than in the baseline scenario—delivering 60% more electricity to the grid—the CCS retrofit also displaces higher-emitting sources elsewhere in the system. This results in an additional reduction of 7 million metric tons of CO2, relative to the baseline.

The impact of the CCS retrofit on plant-specific and systemwide emissions over the study period is illustrated by the first two bar graphs from the left on **Figure 2** below. As shown, the new, minimal emitting supply from a CCS retrofit reduces emissions 17.9 million tons, assuming demand for electricity remains the same as in the baseline scenario.

<u>Figure 2</u>.



[22] We assume that the CCS equipment has a 95% capture efficiency, which aligns with expected efficiencies of the technologies Calpine has begun piloting. However, though the plant's emissions rate is reduced by the capture efficiency of 95%, the direct emissions amount to slightly more than 5% of the 12 million tons of emissions in the baseline scenario due to increased dispatch associated with the CCS retrofit.

To answer Treasury and IRS' questions about the "direct and induced emissions impacts" of making EACs backed by newly CCS-abated electricity eligible for Section 45V, the relevant question is *how does the use of electricity produced by a CCS-abated NGCC facility change emissions throughout the system*. If total systemwide emissions are no greater than in the baseline scenario, then no induced grid emissions result from the use of that plant's electricity to produce hydrogen. In other words, as long as the use of new minimal-emitting electricity generated by a CCS-retrofitted plant to produce hydrogen does not result in greater emissions than would occur in the absence of the CCS retrofit and the electrolyzer load, then the EACs associated with that minimal-emitting electricity should be considered "incremental."

This is exactly what the Aurora Modeling Results demonstrate. Specifically, as illustrated by **Figure 2**, each additional 150 MW of electrolyzer load increases systemwide emissions of 6.5 million metric tons of CO2. However, as shown in this example, no increase in systemwide emissions occurs relative to the baseline scenario so long as the new electrolyzer load does not exceed the minimal-emitting generating plant's derated capacity, multiplied by its capture rate.[23] The Aurora Modeling Results show an absence of any increase in systemwide-emissions relative to the baseline during every year of the study period.[24]

This conclusion should hold in other regions where CCS-abated NGCC generation might be used to power an electrolyzer. If anything, the incrementality of CCS-abated electricity is likely clearer in other regions with lower projected renewable penetration-rates than ERCOT,[25] where the number of hours during which dispatch of the CCS-abated NGCC plant displaces a zero-emitting resource should be fewer, thereby resulting in *greater* overall indirect emissions reductions.

2. CHP Facility

The same result is obtained under the distinct operating conditions of a CHP plant in ERCOT. Unlike the NGCC example above, a CHP plant may not be dispatched more frequently after installing CCS than it would in the baseline scenario because the CHP plant is likely already operating at a high capacity factor to deliver a relatively continuous supply of steam and electricity to its industrial host. Nonetheless, in the CHP scenario, the CCS-abated facility's electricity will likewise be incremental.

For simplicity, assume a plant of the same size above, also in ERCOT, and with a consistent 90% capacity factor in both the unabated baseline case and CCS-abated case. Assuming the same emission rate as assumed by Aurora (0.4 metric tons per MWh), the baseline direct emissions for the 12-year period would be 18.9 million tons in direct emissions of CO2.[26] But when that plant is retrofitted with CCS, its direct emissions would be reduced by 95% to less than one million tons

[23] (NGCC Plant Rated Capacity (MW) x Derate (%) x Capture Rate (%)) = (525 x .85 x .95) = 403.75 MW.

[24] Aurora Modeling Results, Attachment at 18.

[25] *Id*. at 19-20.

[26] 500 MW x 0.4 MTCO2/MWh x 0.9 x 8,760 hours/year x 12 years = 18,921,600 MTCO2.

—a cumulative decline of nearly *18 million tons*. Thus, because the baseline is a much higher level of unabated gas-fired generation, the CCS retrofit of the CHP facility results in direct emissions reductions more than twice as great as the above (non-CHP) example, despite the absence of indirect emissions reductions. Accordingly, the induced emissions occurring if nearly all of the electricity from such a CCS-abated CHP facility were to be used to power an electrolyzer are zero, so long as the electrolyzer load is no greater than the derated CHP plant's capacity multiplied by its capture rate. EACs associated with electricity from a CCS-abated CHP plant should therefore likewise be deemed incremental.

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In light of the absence of induced emissions demonstrated by the Aurora Modeling Results, Calpine proposes that Treasury and IRS clarify in their regulations that EACs associated with the electricity delivered from a newly-retrofitted NGCC-CCS or CHP-CCS plant are incremental. Accordingly, Calpine recommends that Treasury and IRS revise proposed Treas. Reg. 1.45V-4(d)(3)(i) by adding a new subparagraph (D), as follows:

> *Upgrades*. An EAC meets the requirements of this paragraph (d)(3)(i) if the electricity represented by the EAC is produced by an electricity generating facility that had an upgrade no more than 36 months before the hydrogen production facility with respect to which an EAC is retired was placed in service and the number of EACs retired from the upgraded facility does not exceed the product of the upgraded facility's nameplate capacity and its capture rate. The term *upgrade* means the addition of carbon capture, utilization and storage equipment to an existing natural gas-fired combined-cycle electric-generating facility or natural gas-fired combined heat and power-generating facility. The term *nameplate capacity* means the maximum level of electricity that the generating facility can supply after installation of the carbon capture, utilization, and storage equipment, net of the power needed to operate the facility and such equipment. The term *capture rate* means the percentage of the total amount of carbon oxide in the electricity generating facility's flue gas that the carbon capture, utilization and storage equipment captures for disposal in accordance with regulations established pursuant to paragraph (f)(2) of section 45(Q) of the Code or utilization in accordance with paragraph (f)(5) of section 45(Q) of the Code.

This rule would provide administrative simplicity, addressing concerns about systemwide-emissions while avoiding the need for Treasury and IRS to assess such CCS-equipped NGCC and CHP facilities on an individualized basis. As proposed above, this rule would apply to EACs associated with electricity generated by newly CCS-retrofitted NGCC and CHP facilities in all regions. In any grid, a CCS retrofit will lead to direct emissions reductions and—depending on the extent to which the CCS plant increases its generation and the emissions rate of the marginal unit—indirect emissions reductions. In ERCOT, the indirect emissions reductions achieved as a result of the CCS retrofit are offset by hours during which dispatch of the CCS-retrofitted facility is projected to displace zero-emitting generation, whereas in other regions with lower renewable penetration-rates than projected for ERCOT over the study period, those hours are likely to be *fewer* and, hence, the indirect emission reductions *greater*. Accordingly, Calpine believes the conclusions of its analysis in ERCOT should apply in other regions as well. However, to the extent that Treasury and IRS identify particular circumstances and regions other than ERCOT where the potential for induced grid emissions precludes an ex-ante determination that EACs from a CCS-retrofitted NGCC facility are incremental, they should provide a streamlined process for DOE to approve a source- and region-specific determination based on modeling similar to that provided herein.

By confirming that EACs from a CCS-abated NGCC or CHP facility are incremental or providing a process by which a taxpayer can demonstrate their incrementality, Treasury and IRS would achieve their dual goals of (1) ensuring that the Section 45V rules incentivize the production of clean hydrogen to decarbonize hard-to-abate sectors and (2) safeguarding against any potential increase in power-sector emissions. Additionally, it would also help support the deployment of CCS, another key goal of the IRA, and assist DOE and the Environmental Protection Agency (EPA) in achieving their goals.[27] Even if EACs from a CCS-abated NGCC facility are deemed incremental, a taxpayer seeking to rely upon and retire such EACs to receive a Section 45V credit would still need to demonstrate that its hydrogen production process qualifies for such a credit using the most recent version of the GREET model.

C. Emissions from NGCC Plants Are Measured on an Hourly Basis

Treasury and IRS requested comment on what information would be needed to allow for EACs representing existing fossil fuel-powered electricity from facilities that have added CCS to qualify as incremental.[28] Calpine believes that, due to the high-quality emissions data reported by operators of NGCC plants, sufficient information should be available to support the use of qualifying EACs associated with electricity generated by NGCC plants that retrofit with CCS.

Electricity generating units regulated under the Clean Air Act's Acid Rain Program—which

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[27] *See* DEP'T OF ENERGY, PATHWAYS TO COMMERCIAL LIFTOFF: CLEAN HYDROGEN 1 (Mar. 2023), https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf (noting the Department of Energy's goal of 50 million metric tons of hydrogen production per year by 2050); *see* New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240, 33,309 (May 23, 2023) (citing the Department of Energy's goals for the growth in the supply of hydrogen to support a proposed rule under the Clean Air Act selecting a "best system of emission reduction" for gas-fired power plants based on co-firing clean hydrogen).

[28] *See* 89 Fed. Reg. at 89,229.

includes all plants likely to implement CCS—are required to monitor and report CO2 emissions.[29] The regulations permit operators to comply either by (1) using continuous emission monitoring system (CEMS) and a flow monitoring system to determine CO2 mass emissions in tons/hr; (2) measuring the carbon content of the fuel and the amount combusted to estimate CO2 emissions in tons/day; or (3) using a flow monitoring system and a CO2 CEMS that uses an O2 concentration monitor to determine CO2 mass emissions in tons/hr.[30] The regulations also permit sources to comply with these regulations using alternative monitoring systems, provided the operator has obtained EPA's prior written approval.[31]

As these required monitoring approaches establish each facility's hourly CO2 emissions and output and require electronic reporting to EPA, any NGCC facility equipped with CCS will be able to establish its GHG emissions and the carbon intensity of each MWh generated during each hour. Moreover, the current 45VH2-GREET model already allows a user to designate an NGCC facility with CCS as the electricity source and includes a pull-down menu so that a user can specify the "NGCC CO2 Capture and Storage Rate."[32] By the time hourly matching would be required under the proposed regulations, EACs associated with electricity delivered from such a facility should be able to be linked to the hourly emissions and output reported pursuant to the Acid Rain Program to provide an auditable, verified record of emissions intensity in any such hour. Additionally, for this reason, Treasury and IRS need not specify any minimum capture rate necessary for EACs associated with electricity from a CCS-retrofitted NGCC facility to qualify as incremental, as the capture rate is a required piece of foreground data specified by the user within the 45VH2-GREET model, which will determine whether the capture rate is sufficient and lifecycle emissions are low enough for hydrogen produced using such electricity to qualify for the 45V credit.

In short, a hydrogen producer receiving minimal-emitting electricity produced by a CCS-retrofitted NGCC facility will have sufficient high-quality auditable information to establish which tier of the tax credit its production process meets.

D. Policy Developments Will Spur a Market for Responsibly Sourced Natural Gas

Finally, Treasury and IRS ask about the "readiness of verification mechanisms that could be utilized for certain background data in 45VH2-GREET if it were reverted to foreground data in future releases."[33] Specifically, the agencies note the possibility that "upstream methane loss rate" is currently background data but in future releases may become foreground data based on "certificates that verifiably demonstrate different methane loss rates for natural gas feedstocks,

[29] *See* 40 CFR § 72.6 (describing applicability for the Acid Rain Program provisions); 40 CFR § 75.3 (providing that the Part 72 applicability provisions govern Part 75, which includes the CO2 monitoring provisions).

[30] 40 CFR §§ 75.10(a)(3)(i)-(iii), 75.13(a)-(c).

[31] 40 CFR §§ 75.10(a)(3); *see generally* 40 CFR Part 75, Subpart E.

[32] Argonne Nat'l Lab., https://www.energy.gov/eere/greet (last accessed Feb. 23, 2024).

[33] 88 Fed. Reg. at 89,225.

sometimes described as responsibly sourced natural gas."

Calpine agrees that upstream methane loss rates are highly likely to become foreground data. As part of the Inflation Reduction Act, Congress added Section 136 to the Clean Air Act, which directs EPA to "impose and collect a charge on methane emissions [from sources] that exceed an applicable waste emissions threshold" beginning in 2024, but exempting sources from the charge if they comply with methane emissions requirements under Section 111 of the Act.[34] EPA recently finalized its Section 111 rule.[35] Upon publication of the 45VH2-GREET model, DOE specifically acknowledged "that the landscape for methane emissions monitoring and mitigation is changing rapidly," in light of these developments, and that the GREET model will continue to be updated to reflect changes in methane leak rate estimates.[36]

As the methane charge is now in effect and EPA's rules will require reductions in methane emissions throughout the natural gas supply chain, oil and gas producers will have strong incentives to achieve reductions in methane leak rates. This will likely lead to significant market development of certificates that some natural gas is "responsibly sourced" and, at the very least, should cause overall leak rates to decline significantly. As these developments occur, Argonne National Laboratory is likely to update the 45VH2-GREET model to include differential methane loss rates as an input, either as a result of regional differentiation, the availability of certificates associated with procurement and use of responsibly sourced natural gas, or more dynamic data sets on leak rates. Once this happens, taxpayers should be able to demonstrate the precise lifecycle greenhouse gas emissions rate of a given unit of electricity from a CCS-abated NGCC plant based on its natural gas feedstock.

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For the foregoing reasons, Calpine encourages Treasury and IRS to conclude that, for purposes of Section 45V, electricity generated by a CCS-retrofitted gas-fired power plant is "incremental" for purposes of a taxpayer using that electricity to produce hydrogen in an electrolyzer. This clarification is essential to provide regulatory clarity and to ensure that Section 45V achieves Congress' intent to scale the production of qualified clean hydrogen to abate emissions from other hard-to-abate sectors.

Please contact me at 713-830-2000 or Steven.Schleimer@calpine.com with any questions

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[34] 42 U.S.C. § 7436(c), (f)(6).

[35] *See* Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (prepublication version), available at https://www.epa.gov/system/files/documents/2023-12/eo12866_oil-and-gas-nsps-eg-climate-review-2060-av16-final-rule-20231130.pdf.

[36] Dep't of Energy, GUIDELINES TO DETERMINE WELL-TO-GATE GREENHOUSE GAS (GHG) EMISSIONS OF HYDROGEN PRODUCTION PATHWAYS USING 45VH2-GREET 2023, December 2023, https://www.energy.gov/sites/default/files/2023-12/greet-manual_2023-12-20.pdf, at 16-17.

regarding these comments.

Sincerely,

Steven Schleimer
Senior Vice President,
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