Assessment of Studies on US Hydrogen Tax Credits and Potential Takeaways for Scope 2 Guidance

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I. Introduction

In the context of Section 45V of the U.S. Clean Hydrogen Fuel Credit ("45V") production tax credit (PTC), a number of studies have proposed and examined different approaches to greenhouse gas (GHG) emissions accounting and clean energy procurement.[1] These studies have informed the U.S. Treasury's Proposed Rulemaking regarding the Section 45V Credit for the Production of Clean Hydrogen.[2] In this memo, we provide a summary and assessment of the supporting modeling method and evidence from a select number of representative studies, the claimed advantages and disadvantages associated with different approaches, and the implications of their results. Though this evidence has been primarily developed in the context of 45V, we assess this evidence in terms of its broader relevance to the Greenhouse Gas Protocol's ongoing efforts to update its Scope 2 Guidance.

Under 45V, hydrogen producers can be eligible to receive 10-year PTC for clean hydrogen produced from qualifying facilities. The exact magnitude of the PTC depends on life-cycle emissions of the produced hydrogen, as well as whether the project meets conditions on wages and apprenticeship.[3] Electrolysis, a technology that extracts hydrogen from water using electricity, offers a pathway to producing emissions-free hydrogen when paired with clean electricity. Hydrogen producers can procure clean electricity via:

- **Physically delivered clean generation**: For example, on-site electricity generation assets such as solar photovoltaic (PV) can supply clean electricity directly to electrolyzers.
- **Clean energy procurement**: Electrolyzers are powered by grid electricity, which is generated from both renewables and fossil fuel resources. To qualify as "clean," the hydrogen producer must procure clean electricity from elsewhere to match the electricity input.

1 "26 USC 45V: Credit for production of clean hydrogen." *Via* www.uscode.house.gov. Retrieved Jan 30, 2024

2 Comments for this Rulemaking are due February 26, 2024. A public hearing is scheduled for March 25, 2025. *Via* Internal Revenue Service and Department of the Treasury. "Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property." *FederalRegister.gov.* Dec 26, 2023.

3 Specifically, the full PTC value is \$3/kg (with full incentives associated with employment and other provisions) for hydrogen production with emissions less than 0.45 $kgCO_2e/kgH_2$; about 33% of the full credit value for emissions between 0.45–1.5 $kgCO_2e/kgH_2$; 25% of the full credit value for emissions between 1.5–2.5 $kgCO_2e/kgH_2$; and 20% of the full credit value for emissions between 2.5–4 $kgCO_2e/kgH_2$. The full PTC value translates to approximately \$100–400/tonne of emissions avoided by the H_2 depending on what fuel consumption activity the H2 is anticipated to displace in the economy. Krupnick, Alan and Aaron Bergman. "Incentives for Clean Hydrogen Production in the Inflation Reduction Act." *Resources for the Future*. Nov 9, 2022 (Retrieved Jan 30, 2024). And Kaufman, Noah and Anne-Sophie Corbeau. "The Battle for the US Hydrogen Production Tax Credits." Center on Global Energy Policy. Apr 17, 2023.

While the clean energy procurement approach presents a flexible strategy, there are significant disagreements over how exactly clean energy should be matched with hydrogen production to ensure accurate measurement of GHG emissions caused by the hydrogen production and to balance other policy objectives. Of the many accounting approaches proposed by the various studies, we categorize the options for demonstrating that procured electricity is entirely GHG-free as:

- **Annual matching**: the annual electricity consumption must match the total procured clean electricity on an annual basis.[4]
- **24×7 matching**: electricity consumed from the grid must be matched by the same amount of procured clean electricity injected into the grid, with matching applied on an hourly basis and certain locational requirements (e.g., procured electricity must be sourced from the same power system that serves hydrogen load).[5]
- **Three pillars**: in addition to 24×7 matching, the procured electricity must be deliverable to the location where it is used and "incremental," meaning the clean electricity resource would not have been developed or in operation but for the demand from the hydrogen producers[6]
- **Marginal emissions matching:** Procured clean electricity should match its avoided marginal GHG emissions with the GHG emissions caused by energy consumption, measured as the tonnes/MWh of GHG emissions deemed avoided by each MWh of clean energy injected (or caused by consumption). The concept is to maximize the impact to reduce GHG emissions on a system-wide basis, regardless of where or when energy was generated and consumed.[7]

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4 The E3/ACORE study offers a variation of this approach, which allows only environmental attribute credits (EACs) or renewable energy credits (RECs) that are produced under certain conditions (e.g., EACs/RECs generated during non-curtailment hours from newly built resources; see Section II.A).

5 Variations of this concept would allow for the use of hourly bilateral clean energy certificate markets as a means to enable hourly matching of many buyers and sellers, rather than requiring an individual entity to match supply and demand on an hourly basis. Similar variations exist under the "three pillars" approach.

6 We use the terms "incrementality" and "additionality" somewhat interchangeably in this document. Strictly speaking, "additionality" refers to the concept of demonstrating that the clean energy would not have existed absent the contract or other activity. Additionality also refers to the concept of demonstrating that the system-level GHG emissions are lower because of the contract/activity than they would have been in a but-for scenario. In contrast, "incrementality" is used to broadly mean new. However, when discussing each specific study, we aim for precision when describing the study authors' own proposed measures of incrementality or additionality on a resource-specific or system-wide basis, given that these different measures sometimes contribute to their meaningfully different conclusions.

7 Also referred to as an "emissionality" or "impact accounting" approach. The *marginal* grid emissions seeks to consider the incremental GHG impact of the next unit (e.g., 1 MWh) of demand that could be served, including accounting for what specific resource (e.g. coal, gas, or renewable) would be used to serve that demand. The marginal emissions rate will differ in any given hour from both: (1) average grid emissions rate (which accounts for all resources that produce power in that hour, not just the marginal resource); and (2) residual grid mix rate (which considers the emissions rate

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- **Flow-based accounting**: Using granular physical power flow measurements, carbon emissions are traced from where electricity is generated to where it is consumed, and emissions are assigned based on when, where, and how much electricity is consumed.

Below we describe studies that developed modeling analysis comparing one or more clean energy accounting frameworks, their modeling approaches, their primary findings, study limitations, and their relevance to the Greenhouse Gas Protocol (GHGP) Scope 2 Guidance. As an important caveat, we note that a subset of these studies' findings are relevant particularly in the specific context of demonstrating the importance of the additionality requirement in implementing the H_2 PTC, and may not be valid to generalize into the context of the GHGP Scope 2 emissions accounting.

Most of the studies we reviewed set out to examine their research questions using either a capacity expansion model or a production cost model to simulate what the energy systems would look like under various scenarios.[8] At a high level, a capacity expansion model helps determine the MW quantity of resources of each technology that will be most cost-effective solution to supply power in future years given certain constraints, such as decarbonization or renewable energy goals. Through an optimization process, the model selects new energy resources (and retires existing resources) to satisfy the specified constraints and serve total electricity demand at the lowest cost. By comparison, a production cost model optimizes for the least-cost dispatch of grid resources (*i.e.*, which available grid resources should be utilized to serve demand) over a shorter time period (e.g., one year). Production cost models do not examine investment-related decisions related to new construction of generation or transmission capacity. However, depending on model setup and study design, production cost models can (though they do not always) offer the advantage of enabling a more detailed and temporally granular analysis of grid operations, with the option to consider nuanced operational parameters like nodal transmission constraints, generator ramp rates, and start-up times. The appropriateness of a certain modeling choice depends on the research question(s) of interest, and

of resources whose emissions or non-emitting attributes are not already claimed). There are multiple variations of marginal emissions accounting, including: (a) locational marginal emissions (LME) accounting that aims to measure emissions on a locationally granular basis (e.g., at each node of the grid) versus marginal emissions calculated on an hourly basis across larger grid regions; and (b) short-run marginal emissions rates (SMER) that is typically measured in real time or soon afterward based on realized physical grid outcomes; and (c) long-run marginal emissions rates (LMER) that accounts for long-term investment effects and may be defined as a projection of the SMERs that would be avoided by a particular new technology investment over a 20-year period, or as the modeled quantity of emissions caused by a specifically-sized increase in demand over a 20-year period.

8 For a primer on power sector modeling, please see Boyd, Erin. "Power Sector Modeling 101" *US Dept of Energy*. Retrieved Jan 30, 2024.

the selected modeling technique can have significant implications on the proper interpretation of modeling results.[9,10]

[9] For example, a production cost model helps analyze the grid's operations over a snapshot in time, but it does not inform decisions over new construction and retirement decisions, and therefore cannot help answer questions related to additionality. While a capacity expansion model captures the structural/investment effects (i.e., what energy capacity will be built or retired) over long periods, these models do not capture nodal transmission constraints (representation of transmission is typically reflected at a larger regional or zonal level), and thus cannot answer questions related to sub-regional deliverability satisfactorily.

[10] Beyond these grid modeling platforms, we also note the separate role of project finance models, or spreadsheet models that use forecasts of revenue and cost line-items to determine the project's economics and investment worthiness. These inputs are derived from output of analysis using capacity expansion or production cost models, or from prevailing market prices (e.g., historical energy prices or power futures).

II. Review of Representative Studies

A. Analysis of Hourly & Annual GHG Emissions: Accounting for Hydrogen Production

The American Council on Renewable Energy (ACORE), a clean energy nonprofit organization, sponsored the economic consultancy E3 to conduct a study that examines different approaches to procuring clean electricity supply used for hydrogen production, and their implications on the implementation of the 45V tax credit.[11,12] Published in April 2023, the study focuses on the GHG emissions impact, depending on whether the developer must match eligible renewable supply with electrolyzer demand on an hourly basis versus an annual basis.[13] In addition, the study also analyzes the associated cost implications under the two approaches.

The study's method consists of three main steps. First, the authors construct renewable portfolios that are sufficient to meet demand for electricity from a 500 MW electrolyzer via either annual or hourly energy matching. (The renewable capacity volumes needed for hydrogen production are not optimized using a capacity expansion model, and the study does not consider the potential role of batteries to reduce total renewable plus battery supply costs.) The study assumes an annual utilization rate of 90% for the electrolyzer. Hydrogen production and procured renewables are assumed to be located in the same market area and so are treated as inherently "deliverable" for the purposes of the study (e.g., hydrogen located in SPP is matched by renewable generation in SPP, with no sub-regional transmission constraints considered).[14] Under annual matching, the annual hydrogen production is restricted by the annual MWh of renewable generation available in each of the constructed portfolios. For hourly matching, hydrogen production is limited by the available quantity of the portfolio's renewable generation in every hour. The study assumes that no environmental attribute credit (EAC) or renewable energy credit (REC) that may be created during periods of

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[11] Energy + Environmental Economics and ACORE, *Analysis of Hourly and Annual GHG Emissions: Accounting for Hydrogen Production*, April 2023.

[12] Another study conducted by BCG uses a similar approach with similar results, refer to the appendix for more information.

[13] Internal Revenue Service. "Comment from American Council on Renewable Energy." Via Regulations.gov. Dec 6, 2022. EACs/RECs generated during non-curtailment hours are considered eligible.

[14] Matching does not necessarily or automatically imply physical deliverability. The regions that study examines include ERCOT, MISO-North, SPP, and PJM. Given than no sub-regional transmission constraints are considered, this study adopts the assumption within the study design that connection to the same market region or grid area is sufficient to demonstrate deliverability.

curtailed renewable electricity would be eligible for both annual and hourly matching.[15] This study framework seeks to measure the incremental renewable MWh produced by the newly built resource considered for the matching purpose (minus any existing renewable resources that may be curtailed when more renewables are brought online). Put more simply, this accounting method mimics an annual REC accounting methodology under which all RECs produced in renewable curtailment hours would be disallowed or ineligible from being applied toward the matching requirement. This nuance in study approach has important implications for the interpretation of results as we discuss later.

Second, to calculate the emissions impact, the authors simulate the operations of each market of interest using Aurora, a production cost model, for the years 2025 and 2030.[16] And third, they estimate the hydrogen production cost.

Overall, the study finds that in many scenarios, annual matching with only eligible EACs can ensure that GHG emissions caused by electrolyzer demand are close to zero and below the level that qualifies for the full H_2 PTC. In addition, the study authors find that an hourly matching strategy does not necessarily lead to lower net GHG emissions compared to annual matching with eligible EACs. Figure 1 below summarizes the study's findings on the abatement value of hourly matching versus annual matching with eligible EACs compared to findings from other studies (we defer discussion of the large differences across these studies and synthesis of evidence across the studies to Section III farther below). The E3 study also finds that all hourly matching scenarios are more costly than annual matching with eligible EACs (from \$0.35–\$3.76/kgH_2), as summarized in Figure 2 below and as compared to other studies.[17]

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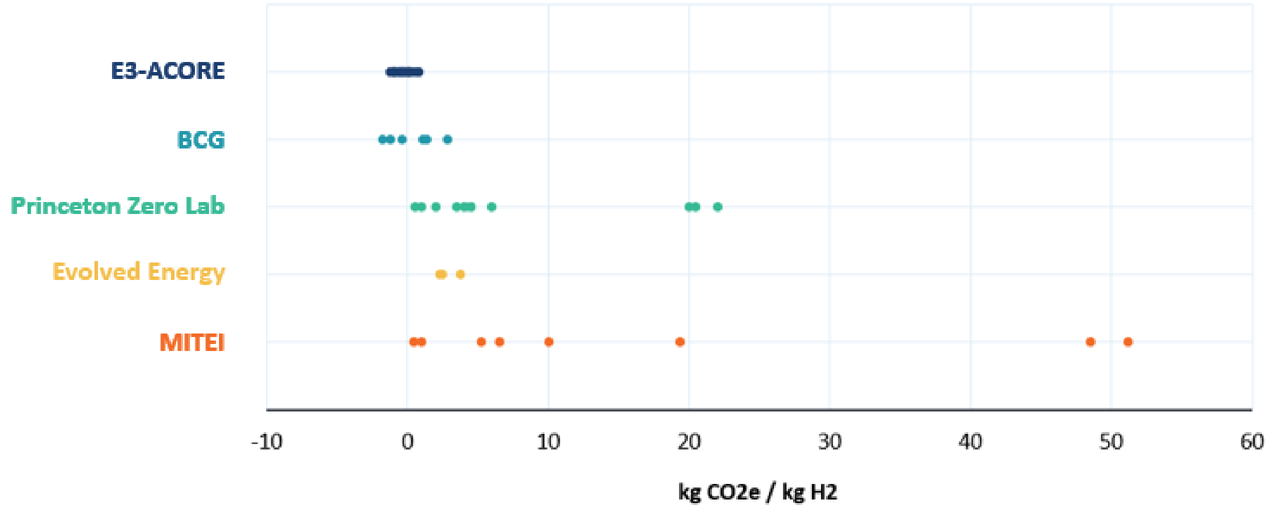
15 In addition, the study also examined an emissions matching approach. At an annual level, this means that the model procures renewables so that the incremental emissions is equal to 0.45 kgCO_2e/kgH_2, the threshold for a full PTC under 45V).

16 The study authors measure incremental emissions as equal to the total emissions that the electrolyzer is directly responsible for causing by using grid electricity, calculated by multiplying the electrolyzer's hourly energy consumption by the hourly (short-run) marginal emissions rate of the grid, *minus* the avoided marginal emissions that can be attributed to the procured renewables, which is also calculated using the grid's hourly marginal emissions rate. This approach to measuring GHG emissions impact based on marginal emissions offers one method to evaluate the study's questions related to the emissions impacts of different matching requirements for hydrogen facilities to qualify for the PTC. However, the results may not be generalized in the context of Scope 2 emissions accounting. Further, we note that this approach is not consistent with guidance from the U.S. DOE, which specifies that methods for estimating life-cycle GHG emissions of hydrogen production need to "take into account induced GHG emissions, considering operational and structural effects." *See* U.S. DOE, "Assessing Lifecycle Greenhouse Gas Emissions Associated with Electricity Use for the Section 45V Clean Hydrogen Production Tax Credit," 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.

17 Another study by the Boston Consulting Group (BCG) has results largely in line with the findings from the E3 study. Since the findings are similar, we discuss this BCG study in the Appendix.

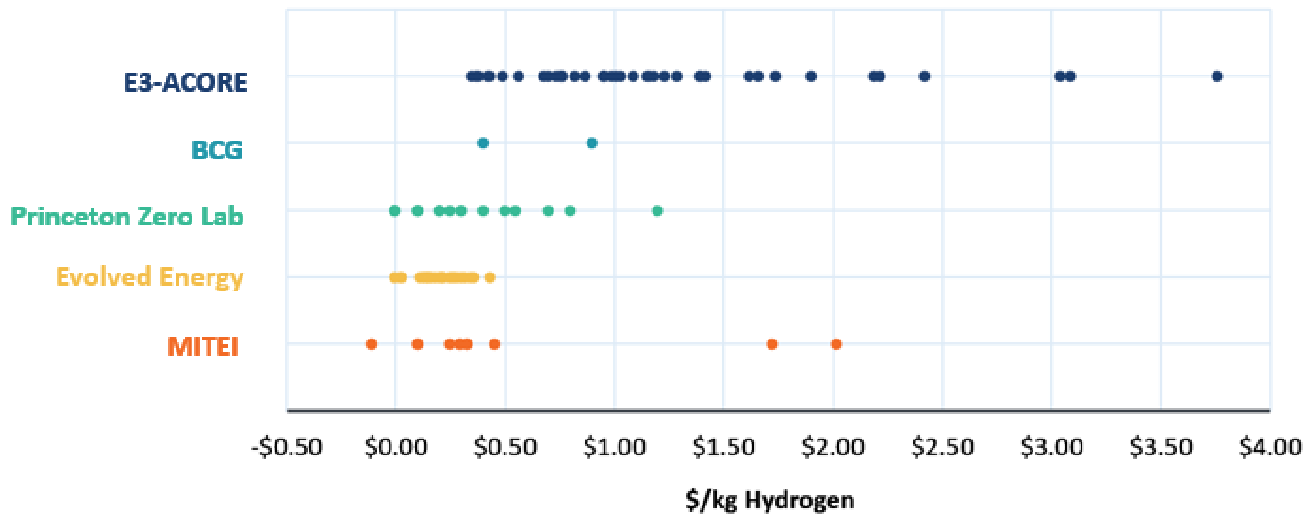
FIGURE 1: EMISSIONS FROM ANNUAL MATCHING MINUS EMISSIONS FROM HOURLY MATCHING ACROSS SCENARIOS



Notes and Sources: Adapted from Bergman, Aaron. "45V Hydrogen Tax Credit in the Inflation Reduction Act: Evaluating Emissions and Costs." *Resources for the Future*, July 14, 2023; Blain, Loz."Record-breaking hydrogen electrolyzer claims 95% efficiency." *New Atlas*, March 16, 2022; IRENA (2020). "Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal." International Renewable Energy Agency, Abu Dhabi; and 26 USC 45V: Credit for production of clean hydrogen" *via* www.uscode.house.gov.. The maximum embedded GHG emissions rate for 45V eligibility is 4 kg CO_2/kg H_2. Emissions rates from gas CC (20 kg CO_2/kg H_2) and SMR H_2 production (10 kg CO_2/kg H_2) are from Wilson, Ricks, *et al*. "Minimizing emissions from grid-based hydrogen production in the United States." *Environmental Research Letters* 18 014025, Jan 6, 2023. MITEI study data updated from more recent results under the "compete" framework" and are consistent with the final version of the study.[18]

[18] Giovanniello et al., The Influence of Additionality and Time-Matching Requirements on the Emissions from Grid-Connected Hydrogen Production, *Nature Energy*, 2024.

FIGURE 2: LEVELIZED COST OF HYDROGEN IN HOURLY MATCHING MINUS LEVELIZED COST OF HYDROGEN IN ANNUAL MATCHING ACROSS SCENARIOS



Notes and sources: For scaling purposes, it is important to note the maximum $3/kg H_2 subsidy rate and the approximate $1.25-$1.50/kg costs of producing H_2 from traditional steam methane reforming (SMR). For further scaling purposes, the $3/kg H_2 subsidy translates to approximately $100-400/tonne of emissions avoided by the H_2 depending on what fuel consumption activity the H2 is anticipated to displace in the economy. $0.4-$1/kg is the "consensus range" of incremental cost for 24×7 matching from across the studies. Adapted from Bergman, Aaron. "45V Hydrogen Tax Credit in the Inflation Reduction Act: Evaluating Emissions and Costs" Resources for the Future, July 14, 2023. MITEI study data updated from more recent results under the "compete" framework" and are consistent with the final version of the study.[19]

Results from the study offer insight into a potential opportunity to adjust Scope 2 market-based accounting by considering only the additional renewable supply produced by a new resource (minus any curtailments that may be induced by new renewables). This approach is equivalent to a matching rule in which no RECs can be utilized if they were created during hours with zero marginal emissions (i.e., in periods of renewable curtailment).[20] The significance of this REC tracking approach is minimal if there are few or no curtailments in a system, but grows if there are many curtailments. In the E3 scenario with the greatest frequency of curtailment hours, this implementation of a matching strategy would exclude RECs produced across up to 25% of all hours (see Figure 17 in the E3 report). A future study could examine the difference in study outcomes under alternative assumed rules in which

19 Giovanniello et al., The Influence of Additionality and Time-Matching Requirements on the Emissions from Grid-Connected Hydrogen Production, *Nature Energy*, 2024.

20 Renewable curtailments at times and places where the volume of renewable supply produced exceeds the volume that can be absorbed in that portion of the grid or exported to demand centers by the available transmission. These timeframes of renewable curtailment coincide with times of high renewable supply. The renewables that do produce power during such intervals are awarded RECs or other green attribute certificates. The determination of which renewables are curtailed (and consequently *cannot* produce RECs) versus which renewables are not curtailed (and consequently *can* produce RECs) is determined by market and grid rules, which do not typically consider online date.

EACs/RECs produced in curtailment hours are or are not eligible to contribute toward annual or hourly matching requirements. The directional implication of such a rule change is obvious by inspection: EACs/RECs produced in renewable curtailment hours have no marginal GHG emissions value and therefore would erode the measured GHG abatement value of the renewable resources in question. The greater the frequency of curtailment hours and associated RECs, the more significantly this value would be eroded. However, it is not obvious by inspection the magnitude of this impact nor the extent that it would more materially affect the measured GHG abatement value of annual matching versus hourly matching strategies.

Several features of the study design should be considered in drawing further takeaways. The study design did not aim to focus on questions of additionality or incrementality (all renewable energy resources procured by hydrogen producers are assumed to be additional), and does not include expansion modeling that would predict investment/retirement effects (i.e., how other resources beyond the procured renewables are built or retired over time) associated with the alternative matching strategies.[21] Further, by modeling a large area for each market without sub-regional transmission constraints, the study aims to capture system-wide implications but does not attempt to address deliverability; the deliverability requirement is assumed to be met if the electrolyzer load and the procured renewables are located in the same market region. Finally, we note that the lower end of cost premium for hourly matching (above the cost of annual matching) is likely to be the more plausible range, given the lack of storage and optimized renewable supply associated with the portfolios that result in high costs.[22]

B. Minimizing Emissions from Grid-Based Hydrogen Production in the United States

Funded by Princeton University's Low-Carbon Technology Consortium, which is in turn funded by Google, GE, and ClearPath, Princeton and Tsinghua University, researchers conducted a study to examine the emissions impacts of hydrogen production using grid electricity under different

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[21] As discussed below, studies such as those conducted by Princeton researchers address the issue of additionality by simulating the grid's composition and operation under a scenario without the electrolyzer and a scenario with the electrolyzer, and comparing the difference in total emissions.

[22] For example, the MISO-North, 2025, All Solar scenario resulting in $3.76/kgH$_2$ in cost difference between hourly matching and annual matching is much higher than the $1.23/kgH$_2$ and $1.29/kgH$_2$ cost differences under the MISO-North, 2025, High Wind scenario and the MISO-North, 2025, 50-50 W/S scenario, respectively. Realistically speaking, developers would not likely pursue a much more expensive all-solar scenario.

implementations of the 45V tax credit.[23] Published in 2023 in Environmental Research Letters, a peer-review journal, the study analyzes the emissions from hydrogen production under five different scenarios:

- 100% hourly energy matching
- 100% weekly energy matching
- 100% annual energy matching
- Marginal emissions matching
- No matching requirements (electrolyzer is added to the grid without requiring any new clean energy additions.

In addition, the study also explicitly evaluates the impacts of regional deliverability and additionality requirements (modeled as “incrementality” further described below).

In each scenario, the study estimates the attributional emissions by following the location-based method from the GHGP Scope 2 Guidance.[24] Further, the authors also calculate the total “consequential emissions,” or the difference in system-level emissions between a world with hydrogen production and a world in which hydrogen production did not occur. To accomplish this, the authors use a capacity expansion and economic dispatch model to first simulate the composition and operation of the electricity grid in 2030, and how they evolve with the addition of a single large 1 GW electrolyzer. The model focuses on six zones across the U.S. Western Interconnect and assumes certain transmission capacities across these regions.[25] However, the study assumes that there are no transmission constraints within each region. (We discuss below the implication of this assumption on the deliverability findings below.)

The study finds that under 100% hourly energy matching, attributional emissions are zero across all scenarios (by definition, given that “attributional emissions” refers to the portion of system emissions

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[23] Ricks, Wilson, Qingyu Xu, and Jesse D. Jenkins. "Minimizing emissions from grid-based hydrogen production in the United States," *Environmental Research Letters*, 2023. Our interpretation of the study results are also informed by direct discussion with study authors and their follow-on paper, Xu et al. “System-level impacts of voluntary carbon-free electricity procurement strategies,” *Joule*, 2024.

[24] However, a close reading indicates that paper’s attributional accounting method likely follows the market-based method, instead, where the emissions rate is calculated as net of the procured carbon-free electricity.

[25] The six zones include Northern California, Southern California, WECC North, New Mexico & Arizona, Pacific Northwest, and Wyoming & Colorado.

claimed by a reporting entity). However, attributional emissions are above-zero under weekly and annual energy matching as well as emissions matching.[26]

With respect to consequential emissions, the study finds that most renewable matching strategies perform worse than would be reported under attributional emissions accounting. The primary reason for this poorer measured performance is the investment effect on renewable supply. The but-for case without hydrogen attracts some renewable deployment (and/or fossil retirement) simply by the virtue that some low-cost renewables are available and lower-cost than fossil supply. However, in the scenario with hydrogen electrolyzer deployment, some of this newly-built renewable supply is diverted for use by the electrolyzer. With limited quantities of low-cost renewable supply available, a portion of the broader grid demand remains to be served by the least-cost generation supply (which tends to be the retention of existing fossil supply or development of new fossil resources that were not cost-competitive in the but-for scenario). The implication of this finding is that “new” renewable supply may not always imply additional carbon-free electricity when compared to a but-for scenario. This is particularly true in a world with limited supply of low-cost renewables.

Estimated consequential emissions impacts also differ across the alternative matching strategies. The study finds that 100% hourly matching leads to lower emissions in most cases (see Figure 1 above), and even negative emissions in some cases. Hourly energy matching can help achieve near-zero GHG impact by requiring 1.5×–3× over-procurement of renewables relative to H_2 demand, and by improving alignment with capacity investment signals. In cases where the electrolyzer is larger (5 GW capacity), the study finds that both attributional and consequential emissions intensity are lower, in part because fossil fuel generators alone cannot meet such a large demand for electricity, and significant new renewables must be built.[27] Another study by the Evolved Energy Research (EER) has results largely in line with the findings from the Princeton study. Since the findings are similar, we discuss this EER study in the Appendix.

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[26] While the study only reports and does not discuss these results in detail, these non-zero attribution emissions results can arise because emissions under weekly and annual matching strategies are still tracked on an hourly basis. “Under this accounting framework hydrogen producers incur an emissions penalty whenever they use more electricity than is being concurrently supplied by procured clean resources. They are not able to achieve a negative hourly emission rate by procuring more clean electricity than they consume (aka ‘offsets’).” (page 3)

[27] The difference in attributional emissions intensity is associated with the differences in the definition of both terms. Attributional emissions measures the difference between study runs, including accounting for differences in investment effects. Marginal emissions matching ensures that within a single model run, the hourly marginal emissions displaced by renewable supply production (sum of rates times output across all production hours) are sufficient to offset the hourly marginal emissions caused by electrolyzer demand (sum of rates times consumption across all consumption hours). Results are reported only for the Southern California Zone and Wyoming & Colorado Zone; results for other zones are not reported.

When the authors relax the deliverability requirements (i.e., hydrogen production is in the Wyoming & Colorado zone, but clean energy procurement can be in the Northern CA zone) and retain the hourly energy matching requirement, they find larger consequential emissions intensity. The study design does not allow the authors to study deliverability at more locationally granular levels (e.g., nodal level), which can be important in an area with significant intra-regional transmission constraints. Likewise, when the authors allow existing and mandated renewable energy resources to qualify and retaining the hourly energy matching, they find that the consequential emissions intensity increases for the Southern California zone.[28] Finally, the study finds moderate increases in H_2 supply costs under hourly matching relative to annual matching, about \$0-\$1 per kgH_2 (on the low end but overlapping the approximate \$0.4-\$1 per kgH_2 consensus range estimated across these studies, see Figure 2 above).

We note that there are different specifications for the deliverability requirement (e.g., deliverable at a country level versus zonal or nodal level; or use proxy tests of deliverability) and deliverable clean energy instruments, but the study only examines the zonal specification.[29] The additionality requirement is important to consider, and the study implements this requirement by assuming that only new clean energy resources can be used for hourly matching (this implementation is more closely aligned with the definition of incrementality). However, the study does not offer specific recommendations on how to implement this requirement in practice (the study authors acknowledge that it would not be feasible to require modeling with consequential accounting as the means to demonstrate additionality for specific projects).[30] The study also does not opine on the best way to address the challenge of existing clean energy resources that are critical to decarbonization.[31]

Finally, the study's conclusion that hourly matching can lead to lower emissions than annual matching in certain circumstances must be interpreted carefully considering that the hourly matching requirement also induces the requirement to substantially over-build the quantity of renewables

[28] Results for other matching strategies and for other zones are not available.

[29] As one example of a locationally granular deliverability rule in the context of hydrogen production in Europe, deliverable electricity will be considered as deliverable from a high-price areas to a low-price area, but not the reverse. See European Commission. "Commission sets out rules for renewable hydrogen." Feb 13, 2023, paragraph 12. A similar deliverability test could be reformulated using locational marginal emissions.

[30] "However, this broader definition of additionality is likely difficult if not impossible to enforce, as it requires counterfactual knowledge of which resources would have been developed had the hydrogen producer not made certain procurement choices. However, zero or near-zero market-based prices for EACs are a likely indicator that procured resources are non-additional, as such sales deliver little-to-no additional revenue to clean generators, and thus cannot materially affect capacity entry/exit decisions." (page 10)

[31] For example, allowing only new clean energy resources to qualify would exclude existing large nuclear or hydropower plants, resources that are needed to achieve deep decarbonization in many scenarios but may retire in the absence of revenue from EACs.

relative to demand on an annually matched basis. In other words, it is not yet clear the extent to which the study's finding of superior GHG performance associated with hourly matching is primarily due to: (a) the resulting *system load profile*, *resource mix*, and *operational behavior* induced by the hourly matching regime; versus (b) the propensity of 100% hourly matching to rely on over-building of renewable supply as a strategy (and, by doing so, to impose the associated costs). Pending further analysis to inform the relative importance of these two factors, our own expectation is that both factors may play a partial or substantial role, and that the relative importance may differ greatly for systems at different stages of decarbonization and with different underlying economic fundamentals.

As further complexity to consider, the study's results appear to be driven in large part by the formulation of the hydrogen PTC. The lucrative nature of the 45 V tax credit could attract substantial hydrogen development, which could in turn compete with other voluntary buyers for the renewable supply that may otherwise be used to decarbonize other electricity customers or other parts of the economy. When coupled with the assumption of limited low-cost renewable energy supply, the resulting effects are more pronounced. If renewables are limited in supply (or become very costly to deploy above a certain volume), the question of additionality becomes central. Renewables can be deployed either: (a) to decarbonize the power grid as serving existing customers; or (b) to match H_2 electrolyzer demand. But with limited renewable supply, it is not possible to both support H_2 production demand and decarbonize existing electricity grid uses (or at least it is not possible to do so without paying more or applying more policy requirements). The specific magnitude of the competition effect's impacts on the relative performance of hourly matching in a certain region depends on the energy supply curve (both renewable and non-renewable) in that region. Further, we note that the study does not fully consider the effects of state policies, utility clean energy commitments, and customer decarbonization goals, all of which would compete with H_2 development for renewable supply.[32]

A follow-on study by the same authors provides additional nuance on the superior performance of hourly matching from a GHG emissions perspective as being tightly tied to the question of additionality and renewable investment.[33] The updated study finds that when renewable energy is abundant and low cost, EACs may be available at little to no cost , and so an annual matching requirement can be met without producing a true investment effect. The introduction of an hourly matching requirement in this long renewable scenario can produce scarcity of supply with a certain profile that may induce more resource investment. However, this outcome is not observed in the

[32] The study is light on details of what state policies, utility commitments, and customer goals are included in the model.

[33] Xu et al. "System-level impacts of voluntary carbon-free electricity procurement strategies," *Joule*, 2024

context of a binding clean energy requirement. In such a scenario, both hourly and annual matching are found to produce comparable emissions reductions.

C. Producing Hydrogen from Electricity: How Modeling Additionality Drives the Emissions Impact of Time-Matching Requirements

Funded by the Future Energy Systems Center, an industry research consortium at the MIT Energy Initiative, the paper examines the emissions impacts of the additionality and time-matching requirements for clean hydrogen production.[34] The paper was initially published as a working paper by the MIT Energy Initiative, and more recently as a peer reviewed paper in *Nature Energy* in January 2024.

Using a capacity expansion model, the paper analyzes the emissions impacts of hydrogen production using a 1-GW and a 5-GW electrolyzer in Florida and Texas, representing regions with low and high renewable energy deployment, respectively. The study includes an assumed flat profile for H_2 demand that must be satisfied in each hour via the combination of electrolyzer output and H_2 storage discharging (i.e., meaning that H_2 production cannot be shifted to the most idealized hours without introducing an additional cost). The study evaluates emissions impacts under two different approaches to modeling the additionality requirement as well as the interplay with other decarbonization-relevant policies like renewable portfolio standards and renewable supply installation limits. Under the "compete" framework, all renewable energy resources are in direct competition with one another to serve demand for clean energy for hydrogen production and for other uses, such as electrifying the transportation sector. As more low-cost clean energy resources are procured for hydrogen production, fewer clean energy resources will be built for non-hydrogen activities (relative to what would have otherwise happened in the absence of the hydrogen production). The authors model this framework by conducting two parallel simulations, one without the hydrogen production, and one with the hydrogen production, both for the year 2021.[35] All other factors remain the same. They then calculate the difference in total system emissions between the two cases under the annual

[34] The working paper was eventually published as Giovanniello et al., The Influence of Additionality and Time-Matching Requirements on the Emissions from Grid-Connected Hydrogen Production, *Nature Energy*, 2024. Members of the Center include Chevron, Constellation, Duke Energy, Eversource, Exelon, ExxonMobil, NextEra Energy, Shell, Toyota Research Institute, among many others. *See* MIT Future Energy Systems Center.

[35] Specifically, the authors use "annualized capital costs for new capacity and fixed and variable operating costs for both existing and new generation, storage, and transmission capacity, as well as any costs for load-shedding" (page 5) instead of multi-year modeling.

matching strategy and the hourly matching strategy. As formulated, the compete framework resembles the modeling approach in the Princeton paper and accounts for the potential for H_2 demand to claim the attributes of renewable supply even if those renewables that might have been added in the absence of H_2 production.

Under the "non-compete" framework, H_2 producers procure renewable energy resources with a pre-defined guarantee of resource additionality. To evaluate this framework, the authors use the capacity expansion model to solve for the optimal system without hydrogen production, the baseline system. With the baseline system as the starting point, the authors then determine the optimal amount of additional clean energy resources needed to support hydrogen production and estimate the associated emissions under the annual matching and hourly matching strategy. This way, the procured clean energy resources do not directly compete with clean energy resources needed for other applications.[36]

Overall, the study finds that under the "compete" approach, annual matching causes high levels of consequential emissions that are driven by prioritization of renewables for H_2 over non-H_2 grid loads; in some cases, hydrogen produced with renewable energy is as emitting as traditional steam-methane reforming. In comparison, hourly matching leads to low and even negative emissions in some cases, driven largely by the overbuilding of renewables. On the other hand, the emissions intensity of hydrogen production under the "non-compete" is lower than the threshold permitted by the hydrogen PTC. Across all scenarios and specifications, the study finds that hourly matching leads to higher production cost than annual matching. Scenarios with the highest cost differential between annual and hourly matching assume no flexibility in the electrolyzer consumption profiles, and a modest level of assumed flexibility in the electrolyzer consumption can greatly reduce the costs of achieving hourly matching.

The study also quantifies the interaction between temporal-matching requirements and decarbonization policy in the "compete" framework. For instance, if non-H_2 grid demand is subject to binding decarbonization policy like an renewable portfolio standard, then the study shows that annual time-matching can achieve low and even negative emissions under a "compete" framework as well as lower costs compared to hourly matching. In the case of limited renewables deployment, e.g., due to interconnection or supply chain constraints, the study finds that hourly matching could substantially

[36] The non-compete framework has some common elements with the modeling design in the E3 study. Both assume renewable energy resources procured to produce hydrogen are additional. However, whereas the MIT study calculates differences in total system emissions (*i.e.*, consequential emissions), the E3 study estimates emissions difference by measuring the marginal emissions and avoided emissions associated with hydrogen production and clean energy procurements, respectively (while assuming hydrogen production does not change the marginal emissions rates).

increase overall grid emissions because the limited renewables would be used to meet H_2 demand, and consequently more fossil supply would have to be deployed to serve other customers.

This study bridges the methods and results found in the E3 study and the Princeton study, clarifying that different approaches to modeling additionality can lead to significantly different results. Namely, if one does not consider long-run investment effects (as are excluded in the E3 study and the "non-compete" framework) and the interaction with other policies, then one cannot assess whether factors such as the competition for scarce renewable supply or EACs generated from projects that were going to be built anyway may undermine the presumption of project "incrementality" or "additionality" that is often associated with newly built resources. The study also aligns with the other studies by finding that hourly matching as defined by Scope 2 Guidance often comes at a cost premium relative to annual matching as well as confirming that the hourly matching cost premium and improved GHG performance relative to annual matching are driven at least in part by the tendency to induce more total renewable development in some circumstances.

Further, we note that the MIT study models only two regions and does not discuss deliverability. The study also affirms our earlier observation, which is that the hydrogen tax credit, when combined with limited supply of low-cost renewables in certain situations, may use up the limited low-cost renewable supply that may otherwise have been deployed to decarbonize other parts of the power grid; or that an excess of EACs from projects that would have gone forward even without EAC revenue could be sold to hydrogen producers. This is particularly noted in the absence of any grid decarbonization policies and could produce overall more GHG emissions in the power grid than would have been produced absent any hydrogen deployments. However, in the presence of grid decarbonization policies like a binding RPS, the relevance of temporal matching in mitigating emissions impacts of hydrogen production is limited. This dynamic makes it difficult to disentangle how effective different clean energy procurement approaches can be in limiting greenhouse gas emissions.

D. Paths to Carbon Neutrality: A Comparison of Strategies for Tackling Corporate Scope II Carbon Emissions

The marginal emissions matching approach nets the marginal displaced emissions associated with clean energy investment against the marginal emissions of a customer's energy usage on a regular basis (e.g., hourly), recognizing that the matching is done irrespective of where or when energy was generated and consumed.[37] This marginal-impact-centric accounting approach incentivizes siting and sourcing clean energy from locations with the highest locational marginal emissions (LME). Under funding from Meta Platforms, the study authors at Tabors Caramanis and Rudkevich (TCR) evaluate the costs and emissions impacts of an LME-based carbon matching strategy, where avoided emissions must equal or exceed the carbon emissions attributable to load over the course of a year, relative to three other clean energy procurement strategies:

- **Annual energy matching**: to match annual energy usage, clean energy can be procured from any of the five RTOs: CAISO, ERCOT, SPP, MISO, and PJM
- **Local annual energy matching:** similar to annual energy matching, but clean energy must be located in the same area (*i.e.*, balancing authority) as demand
- **Hourly energy matching**: clean energy is procured locally to match demand on an hourly basis (storage is allowed)

The study examines the costs and emissions impacts of a customer with a flat load profile and a customer with a commercial retail load profile for each of the five regions of interest, for a total of 10 different customer profiles.[38] To determine the five energy systems' characteristics such as location marginal emission (LME) rates and market prices in 2025, the authors use a capacity expansion model and a production cost model. The capacity expansion model helps determine the future makeup of the grid, including what and how much different energy resources will be online given constraints such as costs, reliability, and policy requirements. The production cost model uses outputs from the capacity expansion model as inputs and simulates hourly grid operation to produce geographically granular LME rates and market prices. Note that while this paper also uses a capacity expansion model, it focuses on the net carbon footprint (i.e., emissions resulting from energy consumption minus avoided emissions; both the emissions from the energy consumption and the avoided emissions are calculated using short-run marginal emissions rates) and does not calculate changes in system-wide emissions between cases. That is, the study does not attempt to evaluate and report consequential emissions in the same fashion as the Princeton and MIT studies (i.e., including long-run

[37] Tabors Caramanis Rudkevich, Paths to Carbon Neutrality: A Comparison of Strategies for Tackling Corporate Scope II Carbon Emissions, June 2023. In another peer-reviewed article, the group describes how the marginal emissions rate method can be used to account for GHG emissions. *See* He, H. et al., Using marginal emission rates to optimize investment in carbon dioxide displacement technologies, The Electricity Journal, 2021, available at .

[38] The five locations are based in the following five different balancing authorities (which function as grid operators): Los Angeles, California, Oregon, the Carolinas, and PJM. Note that the Los Angeles area has a different balancing authority the much of the rest of California.

effects), thus making it more challenging to compare results across these studies.[39] The study also does not report attributional emissions outcomes under either a scope 2 location-based or market-based accounting method. Rather, the study focuses on demonstrating that use of locational marginal emissions as a metric and advocates for its use as the most cost-effective approach for identifying investments for emission displacement.

Overall, the study finds that *carbon matching* using LME as a metric, by definition, achieves carbon neutrality. For annual *energy matching* and local annual energy matching, emissions avoided by supply are not always higher than emissions caused by demand. While hourly energy matching produces a negative carbon footprint, the study finds that it has the highest carbon abatement cost ($/metric ton of CO_2) across all 10 matching specifications, and that it is approximately 7-14 times more expensive than the carbon matching strategy.[40] The LME-based carbon matching strategy consistently shows the lowest $/tonne GHG abatement costs.

The implication of the study findings is to support the idea that marginal emissions matching serves as a potentially useful tool for driving clean energy financing and operations to focus on displacing the greatest amount of GHG emissions, regardless of when and where clean energy should be produced. In our view, another potential use or relevance could be to use LME as the means or a partial means to implement an additionality requirement (e.g., by utilizing annual energy matching as a primary strategy, but also showing that marginal emissions displaced over a period exceeds the marginal emissions caused).[41] However, LME-based accounting is less applicable (or at least an incomplete solution) in the context of attributional Scope 2 emissions inventory accounting, which allocates responsibility for generators' Scope 1 GHG emissions to all customers as their Scope 2 responsibilities.[42]

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[39] However, we note that an NREL study finds that long-run marginal emissions rates outperform short-run marginal emissions rates at estimating the emissions impacts of different interventions. See Gagnon, P. and W. Cole, Planning for the evolution of the electric grid with a long-run marginal emission rate, *Science* 25, 103915, March 2022. Available at https://doi.org/10.1016/j.isci.2022.103915

[40] Because this study focuses on commercial retail load, and not hydrogen load, the reported $/MWh cost results are not comparable to the $/kg$H_2$ costs in studies that focus on hydrogen production.

[41] We note that in this context, both short-run marginal emissions rates and long-run marginal emissions rates can inform the magnitude of impacts. For example, short-run marginal emissions rates can help measure the impacts of operational behavior on a short-term time (e.g., charging and discharging of batteries in a certain location), and long-run marginal emissions rates can help inform long-term structural effects (e.g., the impacts of charging and discharging of batteries on the grid mix over the long run).

[42] One cannot use LMEs directly or in isolation for attributional GHG accounting because the marginal emissions rate in any hour does not match (and is nearly always greater than) the average rate in the same hour. If all demand/consuming entities report their emissions using LMEs without adjustment, the resulting total emissions would be almost always greater than the total actual emissions as measured by generators' physical Scope 1 emissions.

It is important to note that the study's definition of carbon neutrality does not consider structural effects and does not estimate the changes in system-level emissions.[43] The study also does not address the issue of additionality directly. There is no requirement to ensure that the carbon neutrality claim by the reporting organization using this approach has to align with the conditions of the electricity system that serves the organization or with how the system's emissions change over time. To the extent that structural effects are material, that may affect whether carbon neutrality can be achieved from a system-level perspective. In addition, while the study sets out to examine deliverability, its definition of deliverability is still quite broad (like other studies examined in this memo), assuming electricity to be deliverable if load and generation are located in the same balancing authority. Finally, we note that LME data are not yet widely available in all market regions. PJM is the only US RTO that has released LME data to date, and modeled regional and nodal LME data are available through third-party data providers.[44]

E. Carbon Tracing

Carbon tracing (also known as flow-based accounting) tracks emissions over the power grid, from generators to customers in a manner that is consistent with granular physical power flow measurements. The approach can be applied on a broad regional basis but can also be applied in a granular hourly fashion with locational granularity down to the nodal level. In simple terms, the approach assumes that as electricity flows through the grid, the associated GHG emissions follow proportionally to power flow across the same network elements. The emissions are assumed to be mixed fully at each bus (where incoming and outgoing circuits are connected), resulting in uniform downstream emissions concentration. Emissions responsibility is then determined by each customer's energy consumption level, as well as where and when that consumption takes place, such at all

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43 The study defines carbon neutrality as "achieving a net carbon footprint of less than zero" by measuring "the difference between carbon attributed to electricity consumption and carbon displaced by clean energy generation." (pp. VI-6 – VI-7)

44 The reporting LME data are consistent with realized system conditions and reported after the fact. PJM notes "the marginal units – and the marginal emissions rates based on them –, cannot provide any prediction of the results of an action." See PJM, Marginal Emissions Rate – A Primer. The ISO-NE, NYISO, MISO, and SPP are working to release similar LME data. Proprietary LME data are available through third-party data providers such as ReSurety and WattTime. It might be more difficult to get access to these LME data in regions without an organized wholesale energy market, such as the Southeast United States.
See "REsurety and WattTime to Make Marginal Emissions Data Widely Available to Support More Impactful Climate Action." *REsurety.com*, January 10, 2023.

customer-side emissions are equal to all generation-side emissions. Some have proposed to use this carbon-tracing approach in the context of location-based emissions accounting.[45]

In principle, carbon tracing can provide the most time- and location-granular approach to allocating average GHG emissions, and it directly incorporates deliverability in its calculations. However, to our best knowledge, there have not been any studies yet on the accuracy and cost-effectiveness of this method to date, and therefore a comprehensive assessment of trends and findings pertinent to this emissions accounting approach is not feasible at the moment.[46] Further, as it is currently specified, the carbon flow-tracing approach is a location-based attributional accounting methodology. The concept would have to be further extended to align with a new set of market instruments and/or residual emissions accounting to support market-based accounting. Given that carbon-tracing data, instruments, and markets do not yet exist, it would not be immediately feasible for all jurisdictions and users to adopt this technique, but given the quick-changing landscape, we note that Scope 2 Guidance should at least consider the potential that carbon-tracing and other advanced GHG accounting techniques will become available in the coming years.

[45] See C. Kang *et al*., "Carbon Emission Flow From Generation to Demand: A Network-Based Model" in *IEEE Transactions on Smart Grid*, vol. 6, no. 5, pp. 2386-2394, Sept. 2015, doi: 10.1109/TSG.2015.2388695. *See also* Chen, Xin, Hungpo Chao, Wenbo Shi, and Na Li. "Towards Carbon-Free Electricity: A Flow-Based Framework for Power Grid Carbon Accounting and Decarbonization." *Via Arxiv.org*. Nov 28, 2023. Retrieved Jan 30, 2024.

[46] Kevala, an energy data and analytics company, using stylized examples shows that a "total carbon accounting" approach, which follows similar calculations as the carbon-tracing approach, leads to more accurate and location-specific emissions rates. However, Kevala's method is not described fully in its public reports. *See* report.

III. Preliminary Takeaways and Potential Relevance for Scope 2 Accounting

The studies differ widely in their findings with respect to GHG abatement value of clean energy procurement strategies. The E3/ACORE study finds that annual matching with eligible EACs performs similarly to hourly matching on the dimension of GHG abatement and at a lower cost. The Princeton and MIT studies offer mixed evidence regarding the GHG and cost performance of hourly matching versus annual matching (as aligned with current Scope 2 Guidance) on the dimension of GHG performance, though the differences in GHG performance are substantially impacted by interactions with policy structures and market conditions. All studies estimate a higher cost to pursue hourly rather than annual matching, but with substantial divergence in scale. The reasons for the substantial differences in findings amongst the studies (and between scenarios within a study) have to do with both study design and what market/policy conditions are assumed in each scenario.

The E3 study takes a study approach to consider a fixed resource mix and measures the short-run marginal GHG impacts of hourly versus annual matching strategy. It takes as an a priori assumption that renewables procured by H_2 producers can be presumed to be additional, and does not consider the long-term system investment effects that could be induced compared to a but-for investment scenario.[47] Using this assumption and approach, one can estimate the incremental GHG impacts that should be expected from modest net changes to supply or demand.[48] These studies aim to consider the *system-wide* incremental GHG impacts caused by taking a *private view* of hourly or annual matching (where matching is based on an individual customer's load profile and not an aggregate demand for clean energy). Considered from a system-wide GHG emissions perspective, hourly matching may perform better or worse than annual emissions matching depending on the matching specification (e.g., whether EACs/RECs must be generated from newly built resources during non-curtailment hours), the specific context, and particularly in the short term.[49] The potential for hourly

[47] Accounting for the investment effects would likely increase the overall emissions, though the exact level and extent would depend on the specifics of the grid in question (namely, on the level of renewable penetration in place and on the levelized net cost of emitting and non-emitting supply available, and whether the availability of low-cost renewables is in tight supply).

[48] However, we note that some research shows that that long-run marginal emissions rates, which include structural effects, are lower than short-run marginal emissions rates, and relying solely on the latter may overestimate the emissions benefits.

[49] There are circumstances when either hourly or annual matching can displace greater emissions (measured relative to marginal emissions impacts). As an example of when hourly matching can perform worse than annual matching from a

Continued on next page

matching to misalign with a system view of emissions reduction value would tend to diminish if many customers and renewable providers pool their net supply and demand into a joint market, and as a system becomes increasingly decarbonized.

The annual matching strategy in the E3 study incorporates or indicates various strategies to augment and improve the performance of annual matching to ensure that the net estimated grid impact is GHG-neutral (or close to it). The most meaningful of these strategies assumes renewable MWh produced in hours with zero marginal emissions (when renewables are being curtailed) cannot be used to contribute toward the annual match.[50]

The studies that use capacity expansion modeling (Princeton, MIT, EER) to compare hourly matching and annual matching (as aligned with Scope 2 Guidance) strategies considered the combined effects of H_2 demand and renewable production on power plant investments, retirements, and operations. In those studies, the dominant effect observed is the high demand for renewables from H_2 development. When combined with assumptions of limited supply of low-cost renewables (i.e., limited availability of locations with abundant wind or solar resources) and no explicit grid decarbonization policies, the studies find that renewables that would be used to serve other parts of the economy are instead prioritized for hydrogen production. With limited volumes of low-cost renewables available, GHG-indifferent states and consumers would tend to extend their reliance on existing and new fossil resources to meet demand for electricity from sectors that do not require clean electricity (perhaps because their incentive to use clean electricity is smaller than that of clean hydrogen producers'). Further, hydrogen producers may purchase RECs generated from projects that were going to be built anyway. The net effect is that the H_2 subsidy could have the unintended impact of increasing system-wide grid emissions in regions without binding system-wide grid decarbonization policies; this effect of increasing grid emissions is anticipated regardless of whether the H_2 producers pursue annual or hourly matching strategies. All three studies find that the increases in grid emissions would be smaller (but not eliminated) by an hourly procurement strategy compared to annual matching. The studies

GHG emissions perspective, consider a scenario in which solar is the renewable supply resource and produces excess supply in the middle of the day relative to the H_2 offtaker. If the excess solar can be sold into the power grid at these times in an annual matching strategy, it may displace high-emitting gas peaker plants (leaving the electrolyzer to charge from grid power during the nighttime hours when others' excess wind production might otherwise be curtailed). In this circumstance, applying an hourly-matching constraint would require the excess solar to be stored in a battery and discharged overnight (the opposite of what a battery would do if seeking to reduce system-wide emissions).

[50] In addition, both the E3 and BCG studies considered strategies of incorporating electrolyzer flexibility to avoid drawing electricity during the top 10% high-price hours (which also tend to be high-emissions hours). BCG also considered 10% excess renewable procurement as a strategy, while E3 examined a scenario in which renewable procurements were increased or decreased until marginal emissions offsets would exactly offset marginal emissions caused by electrolyzer demand.

also examine alternative modeling assumptions (such as making more low-cost renewable supply available or incorporating grid decarbonization policies like an RPS) that would also reduce the scale of the problem.

These expansion studies indicate certain conditions in which hourly matching is likely to produce superior GHG performance than annual matching. Although it is not possible to fully disentangle all of these effects across the multiple studies, they appear to suggest that hourly matching will out-perform annual matching (as aligned with Scope 2 Guidance) if there is a surplus of low-cost renewable supply and no binding renewable or clean energy requirements. In such a condition, surplus renewables can be used to fulfill annual matching demand even if no new renewable development is incentivized by the associated clean energy demand. At the same time, the surplus renewable in this scenario may not be capable to fulfill hourly matching requirements due to a profile mismatch; as a result, more renewable supply would need to be developed.

Other variations of hourly matching (e.g., the three-pillars approach) of private matching or limited storage ability can also improve GHG performance by requiring substantial over-procurement of clean energy, and introducing costs for that over-procurement. If the excess renewable supply can be sold into the power grid, it can displace fossil supply; in scenarios where excess renewable purchase and sales are large enough it can more than offset the renewable-competition effect and induce net negative emissions in the long run. The MIT scenarios with the highest volumes of net negative emissions also tend to be those that incorporate the most stringent assumptions of inflexible electrolyzer demand, such that they drive the greatest oversupply in renewable purchases (as an insurance for hydrogen producers to always have EACs) and hence the greatest impact toward GHG reductions. None of these studies examined how cost and GHG emissions would compare if enforcing the same quantity of renewable over-procurement across annual matching, 24×7 matching, and marginal-emissions-matching strategies (though doing such a test might clarify the extent to which the matching profile drives results, as compared to the total volume of over-procurement).

The other GHG advantage of hourly matching is often explained as the effect to align with long-run drivers of capacity expansion (e.g., hourly demand profiles typically align more closely with peak or net peak hours driving system capacity expansion), although it is not clear whether this factor is a primary driver of outcomes in these studies since this effect is not reported in isolation from others. In general, we would expect that the improved alignment of hourly matching with capacity expansion drivers to be greatest in high-renewable-penetration systems and in situations where many parties' net hourly positions can be pooled in a common marketplace. However, the emissions impacts and costs of such an arrangement have not been studied at this time.

Appendix A: Other Studies

A.1 Flexible Green Hydrogen: The Effect of Relaxing Simultaneity Requirements on Project Design, Economics and Power Sector Emissions

Published in the peer-review journal *Energy Policy*, the study by authors from the University of Cologne and the Harvard Kennedy School evaluates the emissions and costs impacts relaxing the hourly "simultaneity" requirement for hydrogen production. The authors define simultaneity as green hydrogen being produced at the same time as additional, co-located renewable energy (similar to hourly matching but with the co-location requirement).[51] Using historical data, the authors run a cost-optimization model to minimize the cost of hydrogen production under three scenarios: an island system, market interaction with hourly simultaneity (meaning no electricity purchase from the grid), and market interaction with annual simultaneity. The emissions impacts of hydrogen production are measured using hourly marginal emissions factors. The study finds that the production cost of green hydrogen is lower without a simultaneity requirement than with one (€101 per MWh_{H2} compared to €137 per MWh_{H2}). In addition, the study did not find evidence that would show hydrogen production without a simultaneity requirement would increase GHG emissions. Similar to the E3 study, this study does not use a capacity expansion model and does not evaluate the difference in total system emissions.

A.2 Green Hydrogen: An Assessment of Near-Term Power Matching Requirements

Funded by NextEra Energy, the Boston Consulting Group (BCG) published a study on how annual and hourly energy matching requirements would affect total GHG emissions, industry development, power cost and reliability, and the hydrogen PTC qualification process.[52] The study does not specifically examine the additionality requirement but assumes the new clean energy built for hydrogen production is additional. Similarly, the study does not examine the deliverability requirement, but assumes that clean energy and hydrogen production site are located in the same local grid. The study finds that annual matching combined with strategies to overbuild renewables,

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[51] Oliver Ruhnau and Johanna Schiele, "Flexible green hydrogen: The effect of relaxing simultaneity requirements on project design, economics and power sector emissions." Energy Policy, November 2023.

[52] Boston Consulting Group, Green Hydrogen: An assessment of near-term power matching requirements, April 2023.

shut down hydrogen production when the grid electricity is high-emitting or expensive, or increasing the diversity of clean energy mix would help achieve emissions limit allowed by the hydrogen PTC. Compared to hourly matching, annual matching can lead to higher emissions intensity in some cases (base case, and when combined with the shutdown or overbuild strategy) and lower emissions intensity in other cases (shutdown + overbuild, shutdown + overbuild + diverse resource mix). The study also finds that hydrogen production paired with hourly matching would double the cost compared to annual matching. The study results are largely in line with findings from the E3 study.

A.3 45V Hydrogen Production Tax Credits – Three-Pillars Accounting Impact Analysis

The Natural Resource Defense Council funded Evolved Energy Research (EER) to examine the three-pillars accounting approach (hourly matching, deliverability, and additionality).[53] The modeling approach uses economy-wide and electric sector expansion modeling from 2021-2032 (every two years). Hydrogen demand is either “restricted to a few sectors” or “economic” build out to many sectors. The renewable deployment rate is restricted to 20% industry growth rate. The results show that total system emissions under three pillars is consistently lower than under limited requirements. This finding is consistent with findings from the Princeton and MIT studies, in that the additionality (measured by consequential emissions impacts) of renewable deployment is limited by competition for limited low-cost renewable supply. However, the hourly matching strategy is more expensive than annual matching, in part because hourly matching does not allow for flexible operations.

A.4 Making It Count—Updating Scope 2 Accounting to Drive the Next Phase of Decarbonization

REsurety proposes a Scope 2 accounting method that is based on short-run marginal emissions rate.[54] For each time interval t, Scope 2 emissions are calculated as:

$$\begin{aligned} Scope\ 2\ Emissions_t \ &= \ Marginal\ Emissions\ Rate\ @\ Load_t \ \times \ Consumption_t \\ &\quad - \ Marginal\ Emissions\ Rate\ @\ Generator_t \ \times \ RECs_t \end{aligned}$$

[53] Haley, B. and Hargreaves, J., 45V Hydrogen Production Tax Credits—Three-Pillars Accounting Impact Analysis, Evolved Energy Research, June 2023.

[54] Oates, D.L., Making It Count—Updating Scope 2 Accounting to Drive the Next Phase of Decarbonization, REsurety, October 2022.

This method is similar to the method that an author of the Tabors Caramanis Rudkevich paper previously proposed, and that was used as evidence of net emissions impact in the E3 study.[55] The REsurety paper illustrates how the LME-based accounting method may work in a stylized example power system and shows that it would lead to more granular measures of carbon displacement compared to the annual average and hourly average approaches that use average emissions rates. The study does not examine the relative costs of different accounting methods, but an earlier paper by REsurety finds that LME-driven clean energy procurements leads to lower carbon abatement costs compared to grid purchase, annual matching, and on-site hourly demand matching.[56]

[55] Rudkevich, A. and Ruiz, P.A. Locational Carbon Footprint of the Power Industry: Implications for Operations, Planning and Policy Making, January 2012, Chapter in: Handbook of CO2 in Power Systems, Springer

[56] Oates, D.L. and Spees, K., Locational Marginal Emissions—A Force Multiplier for the Carbon Impact of Clean Energy Programs, REsurety and The Brattle Group, March 2022

Key Terms and Definitions

Below are some key terms and concepts used in the reviewed studies. The provided definitions are based on our observation and understanding of their general usage in the industry. However, in some cases the same term may be used by different studies to refer to slightly different concepts.

- Additionality: a clean energy resource is considered additional if it would not have been built had it not been for the intervention of interest (e.g., hydrogen production). This concept can also refer to the demonstration that the system-level GHG emissions are lower because of the contract/activity than they would have been in a but-for scenario.
- Attributional emissions: emissions that are assigned to a specific consumer or purchaser based on their consumption at any given time
- Consequential emissions: the difference in system-level emissions between a world with an intervention (e.g., hydrogen production) and a world without that intervention
- Deliverability: strictly speaking, electricity is considered "delivered" if it reaches a specific consumer or purchaser based on the flow of power through the connecting transmission and distribution network(s). Different heuristics and proxies have been proposed to evaluate deliverability (e.g., generation and load to be located in the same transmission grid or wholesale energy market, comparing locational marginal emissions rates of generation and load).
- Incrementality: a clean energy resource is considered incremental if it is new, although some use this term and the term "additionality" interchangeably
- Location-based emissions accounting method: emissions reporting is based on the emissions intensity of the electricity grid where operations and energy consumption occur
- Locational marginal emissions rate: similar to short-run marginal emissions rate, but measured at a specific location (e.g., a node on the system)
- Long-run marginal emissions rate: change in system-wide emissions due to a marginal increase or decrease in demand, inclusive of long-run structural/investment effects such as addition or retirement of power plants and their operational behavior.
- Market-based emissions accounting method: emissions reporting accounts for contractual instruments such as renewable energy credits or energy attribute certificates as well as an electricity supplier's specific emissions rates

- Short-run marginal emissions rate: also referred to as marginal emissions rate, this is the change in system-wide emissions due to a marginal increase or decrease in demand and does not capture the potential impact of long-run effects (e.g., investment/structural effects)