

Minimizing emissions from grid-based hydrogen production in the United States

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November 2022

Abstract. Low-carbon hydrogen could be an important component of a net-zero carbon economy, helping to mitigate emissions in a number of hard-to-abate sectors. The United States recently introduced an escalating production tax credit (PTC) to incentivize production of hydrogen meeting increasingly stringent embodied emissions thresholds. Hydrogen produced via electrolysis can qualify for the full subsidy under current federal accounting standards if the input electricity is generated by carbon-free resources, but may fail to do so if emitting resources are present in the generation mix. While use of behind-the-meter carbon-free electricity inputs can guarantee compliance with this standard, the PTC could also be structured to allow producers using grid-supplied electricity to qualify subject to certain clean energy procurement requirements. We use electricity system capacity expansion modeling to quantitatively assess the impact of grid-connected electrolysis on the evolution of the power sector in the western United States through 2030 under multiple possible implementations of the clean hydrogen PTC. We find that subsidized grid-connected hydrogen production has the potential to induce additional emissions at effective rates worse than those of conventional, fossil-based hydrogen production pathways, particularly in regions where coal is a large part of the generation mix. Emissions can be minimized by requiring grid-based hydrogen producers to match 100% of their electricity consumption on an hourly basis with physically deliverable, ‘additional’ clean generation, which ensures effective emissions rates equivalent to electrolysis exclusively supplied by behind-the-meter carbon-free generation. While these requirements cannot eliminate indirect emissions caused by competition for limited clean resources, they consistently outperform alternative approaches relying on relaxed time matching or marginal emissions accounting. Added hydrogen production costs from enforcing an hourly matching requirement rather than no requirements are less than \$1/kg, and can be near zero if clean, firm electricity resources are available for procurement.

1. Introduction

Clean hydrogen has been proposed as a solution to many of the challenges of economy-wide decarbonization, with potential use cases in industry, agriculture, transportation, and energy storage [1–4]. Although the ‘hydrogen economy’ is still in its early stages,

hydrogen’s versatility as an energy carrier and chemical feedstock has made it a critical component of many proposed pathways to net-zero carbon economies [5–8]. To play this role, hydrogen must necessarily have near-zero embodied greenhouse gas emissions. Today most hydrogen is produced through steam methane reforming (SMR), a process that emits roughly 10 kg of CO₂-equivalent for every kg of H₂ produced [9–11]. Hydrogen production with much lower embodied emissions can be achieved through multiple pathways, including SMR with integrated carbon capture and storage and electrolysis of water using low-carbon electricity [7, 12]. Electrolysis is currently the more expensive method of production, with estimated costs on the order of \$5-6/kgH₂ compared with \$1-3/kgH₂ for fossil pathways at historical natural gas prices [10, 11], but is projected to become significantly cheaper as the costs of clean electricity and electrolyzers decline [12, 13].

With the passage of the Inflation Reduction Act of 2022 (IRA), the United States introduced robust new subsidies for domestic production of clean hydrogen (Internal Revenue Code Section 45V) [14]. Hydrogen produced through a process with less than 4 kgCO₂e/kgH₂ well-to-gate lifecycle emissions will receive a production tax credit (PTC) of at least \$0.60/kg, and up to \$3/kg for lifecycle emissions less than 0.45 kgCO₂e/kgH₂. The new PTC (hereafter referred to as the 45V PTC) will be particularly relevant for hydrogen produced via electrolysis, which can achieve near-zero lifecycle emissions when using carbon-free electricity inputs [7, 15, 16]. However, the carbon intensity of hydrogen produced in this manner is highly sensitive to the embodied emissions of its input electricity. For example, electrolysis with an efficiency of 50 kWh/kgH₂ using 100% gas-fired electricity (~ 0.4 kgCO₂/kWh [17]) would produce hydrogen at an embodied emissions rate of roughly 20 kgCO₂e/kgH₂, or double that of SMR. Accurate embodied emissions accounting and enforcement will therefore be essential to ensuring that subsidized hydrogen production from this pathway is truly low-carbon.

IRA statute specifies that GREET, a life-cycle analysis model developed by Argonne National Laboratory, should be used to assess the emissions intensity of all hydrogen production for the purpose of determining 45V PTC qualification [14]. For all hydrogen production pathways, including electrolysis, GREET requires users to determine the generation mix supplying any electricity inputs [16]. Doing so is trivial when hydrogen is produced exclusively using behind-the-meter resources, e.g. on-site wind or solar power, but becomes significantly more complex when electrolyzers are connected to the bulk electricity system. Using the current average US generation mix, embodied emissions from grid-connected electrolysis would be far too high to meet statutory requirements for even the minimum PTC [7, 17].

Still, a grid connection could provide significant benefits for hydrogen producers if carbon-free electricity sourcing can be reliably verified and enforced. Connection to the bulk electricity transmission system could enable producers to procure a diverse portfolio of clean resources whose generation profiles can be stacked to achieve greater electrolyzer capacity factors than would be possible when utilizing resources located at a single site. Grid-based electrolysis could also enable hydrogen production co-

located with end uses (minimizing hydrogen transport costs) at sites where installation of behind-the-meter clean generation would not be feasible. However, it is physically impossible to reliably track flows of power between individual producers and consumers in the bulk electricity system [18, 19], making verification of clean electricity inputs for grid-connected hydrogen producers a significant challenge. If the use of clean electricity cannot be reliably established, it may be impossible for grid-connected electrolysis to meet the statutory requirements for the 45V PTC.

In this paper we present a possible implementation of the 45V PTC under which hydrogen producers could obtain the benefits of an electricity grid connection while reliably claiming embodied emissions equivalent to those of behind-the-meter systems. The proposed solution requires electrolysis grid power consumption to be matched at hourly intervals with physically deliverable clean electricity generation from newly-built (aka ‘additional’) resources. We use electricity system capacity expansion modeling to evaluate the cost and embodied emissions of grid-based hydrogen production under such a requirement. We also evaluate several alternative 45V PTC implementations that relax requirements for hourly matching, deliverability, or additionality, as well as an approach based on marginal emissions accounting. We compare outcomes across policy variants in terms of both emissions attributable to hydrogen production from direct consumption of grid electricity and long-run changes in system-level emissions. The aim of this work is to support ongoing IRA implementation efforts by providing quantitative insight into the climate impacts of alternative policy designs.

2. Methods

In this study we use the GenX electricity systems capacity expansion and economic dispatch model to evaluate the emissions impacts of subsidized hydrogen production via grid-connected electrolysis under a set of possible 45V PTC eligibility requirements [20, 21]. GenX optimizes electricity system investment and operational decisions to maximize social welfare over a given planning horizon, subject to physical and policy constraints, and is configurable to allow for varying levels of spatial, temporal, and operational complexity. The model formulation is designed to replicate the investment and operational outcomes that would be observed under a well-functioning competitive electricity market or in a centrally-planned system. It is therefore suitable for exploring the impact of potential policy designs on long-run outcomes in the electricity sector.

2.1. Modeling Approach

We use GenX to model system outcomes in the western US with a planning year of 2030, taking into account existing state policies as well as new federal subsidies established by IRA for carbon-free electricity production. A six-zone electricity system topology is used to represent key inter-regional transmission constraints in the US portion of the Western Interconnection (see Figure 1), and electricity system operations are modeled at hourly

resolution across 18 representative weeks, which are down-sampled from a full year of hourly data using a k-medoids clustering method. Model inputs, including regional demand profiles and cost, performance, and availability data for generators and storage, are compiled using PowerGenome [22] and are described in greater detail in Xu et al. [23]. Only currently mature, commercially-available grid-scale generation and storage technologies are assumed to be available for deployment by 2030. Geothermal inputs have been adjusted from Xu et al. [23] to reflect updated state policies and resource estimates [24, 25]. All carbon-free generator costs have been updated to reflect IRA tax credits for certain resources: onshore wind and solar power are assumed to receive a production tax credit of \$26/MWh (2022 USD) for 10 years, which is represented in the optimization as the equivalent net-present value subsidy if provided over the full financial lifetime of the project; geothermal, offshore wind, and battery resources are assumed to receive an investment tax credit of 30%. All GenX input and results data relevant to this work are available at Ricks et al. [26], and a high-level overview of input technology parameters is provided in Supplementary Tables 1 and 2.

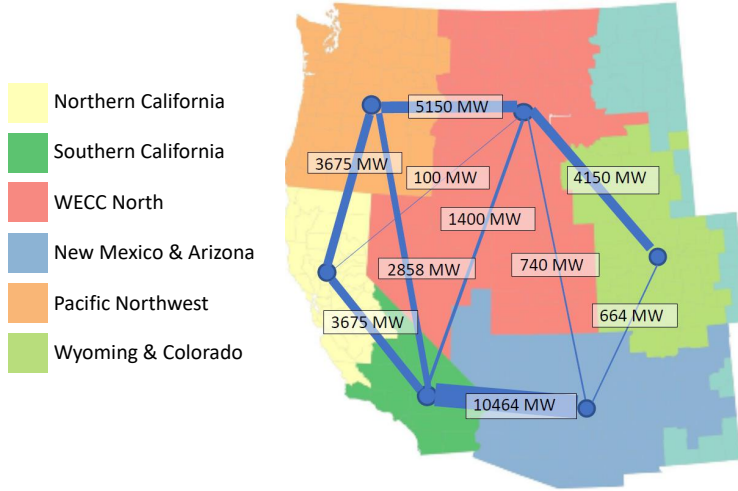


Figure 1. Illustration of the modeled US Western Interconnection electricity system and its component zones, which represent single regions or aggregations of regions from the EPA’s Integrated Planning Model [27]. Existing inter-regional transmission capacities at the beginning of the planning period are shown.

To explore the system impacts of grid-based hydrogen production we exogenously add a single large electrolysis load to a target model zone. The total electrolyzer capacity is fixed, as is the revenue that can be earned per unit of hydrogen produced. Electrolysis operations are co-optimized with the electricity system, and the hydrogen producer is able to curtail production at a given model timestep if the cost of consuming electricity exceeds the revenue that can be earned through hydrogen sales. In addition to purchasing grid electricity to run the electrolyzers, the hydrogen producer can also build on-site energy storage and contract directly with new grid-connected clean energy resources in the local model zone (via power purchase agreements [PPAs] or energy attribute certificates [EACs]) to meet any imposed policy requirements. Because grid

zones in GenX are modeled as ‘copperplates’ with no internal transmission constraints, all locally-procured generation is implicitly assumed to be physically deliverable to the electrolysis facility at all times. We evaluate the emissions intensity of grid-connected hydrogen production in the model via two approaches [28]:

- (i) **Attributional Emissions:** The share of total grid emissions that would be attributed to hydrogen producers based on their net consumption in a given hour, following a convention similar to the current Greenhouse Gas Protocol Scope 2 location-based emissions accounting guidance [29]. The attributional emissions intensity of produced hydrogen is calculated as:

$$I^{Attr} = \sum_t (\max(0, (L_t^{H_2} - CFE_t)) \times E_t^{Avg}) / H_2^{Tot} \quad (1)$$

where $L_t^{H_2}$ and CFE_t are the electrolysis load (including alterations from on-site energy storage) and procured carbon-free electricity at timestep t , E_t^{Avg} is the average grid supply emission rate at timestep t (as described in Xu et al. [23]), and H_2^{Tot} is the total hydrogen production in the system. 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’). This accounting methodology is practically implementable and useful for allocating emissions resulting from *direct consumption* of fossil-sourced electricity, but does not capture the true marginal impact of new loads or the indirect effects of clean electricity procurement and sales on system-level emissions.

- (ii) **Consequential Emissions:** The true long-run electricity system-level emissions impact of hydrogen production, relative to a counterfactual scenario in which the hydrogen production does not occur. The consequential emissions intensity of hydrogen produced is calculated as:

$$I^{Cons} = (E_{H_2}^{Tot} - E_{Base}^{Tot}) / H_2^{Tot} \quad (2)$$

where $E_{H_2}^{Tot}$ is the total system-wide emissions in the case being investigated, and E_{Base}^{Tot} is the total system-wide emissions in a counterfactual scenario where the hydrogen producer is not present in the system. Consequential emissions are impossible to measure in the real world due to a lack of observable counterfactuals, and therefore cannot be used for practical policy implementation or emissions accounting. However, the modeled consequential emissions results presented herein are a useful means of comparing the expected long-run emissions impacts of hydrogen production under alternative 45V PTC implementations.

In addition to emissions rates we also assess the impacts of possible 45V PTC implementations on the cost of hydrogen production. We use GenX results to calculate the levelized cost of hydrogen (LCOH), the total revenue per unit of hydrogen sold needed to make up all associated costs, for each model case under various electrolyzer

cost assumptions. As electrolyzer capacity is an exogenously fixed quantity in the present study, these variations in assumed electrolyzer cost have no effect on other model outcomes presented in this study. The methodology used to calculate LCOH in this paper is described in detail in Supplementary Note 2. Cost and performance assumptions for hydrogen electrolyzers are detailed in Table 1.

Parameter	Units	Value
Installed capacity	GW	Varied: 1 ; 5
Efficiency	kWh/kgH ₂ ; %LHV	50 ; 67
CAPEX	\$/kW	Varied: 1200; 600; 300
Annual fixed O&M	% of CAPEX	5
Capital recovery factor	% of CAPEX	14.9
Grid connection fee	\$/kWyr	85
Hydrogen sales revenue (including PTC)	\$/kgH ₂	Varied: 3; 4 ; 5

Table 1. Electrolysis financial and operational parameters used in this study. Financial assumptions are generally conservative: the large fixed grid connection fee is based on a cost analysis by LADWP for transmission-level customers in Los Angeles [30], and the CRF value assumes a weighted average cost of capital of 8% and a payback period of 10 years, equal to the length of the 45V PTC. The default sales revenue assumes that hydrogen is sold to the end consumer at \$1/kg. Default GenX inputs are shown in bold. Parameters without bolded entries are used only in results analysis and do not affect model outcomes.

2.2. Policy Scenarios

In this study we examine five possible clean energy procurement regimes under which grid-connected electrolysis could be allowed to claim the 45V PTC:

- (i) **No Requirements:** Electrolysis demand is added to the grid without requiring any new clean electricity additions beyond existing state policies, and is met by the least-cost mix of resources.
- (ii) **100% Hourly Matching:** Hydrogen producers are required to match their consumption with procured carbon-free generation at every hour of the year. This policy and its formulation in GenX are described in detail in Xu et al. [23], where it is referred to as ‘24/7 Carbon-Free Electricity’ (or ‘24/7 CFE’). The 100% Hourly Matching requirement effectively mimics the physical constraints on behind-the-meter hydrogen production by requiring producers to never consume more electricity than is being locally generated by a specific portfolio of clean resources. We assume by default that any excess procured carbon-free generation can be sold into the bulk electricity market, reducing overall costs, but we do not credit such sales with reducing the attributional emissions of the electrolysis load (i.e. no ‘offsetting’ of emissions during other periods is permitted). We also assess a subvariant of this regime in which no sales of excess procured generation

are permitted, leading to effectively zero operational interaction with the larger electricity system.

- (iii) **100% Weekly Matching:** Hydrogen producers are required to procure enough carbon-free generation to match their total consumption in every week of the year. Net consumption of grid electricity in some hours may be offset by procurement of excess carbon-free generation in others.
- (iv) **100% Annual Matching:** Hydrogen producers are required to procure enough carbon-free electricity production to match their total consumption on an annual basis. This procurement strategy is commonly employed today in voluntary markets and for compliance with state policies (e.g. renewable portfolio standards).
- (v) **Net-Zero Short-Run Marginal Emissions (Net-Zero SRME):** An alternative approach to time matching based on short-run marginal emissions (SRME) accounting. Hydrogen producers' embodied emissions are evaluated in each hour based on the local short-run marginal emissions rate, the amount by which system-wide emissions would change due to a unit increase in local electricity demand. While this short-run rate is measurable and reflects the impact of changes in consumption or production on the operation of a *static* electricity system, it does not capture the (unobservable) potential impact of these changes on long-run capacity investment and retirement decisions. Under a Net-Zero SRME regime, hydrogen producers are assumed to incur SRME penalties or achieve SRME offsets in a given hour based on the net of total electricity consumed and clean electricity procured, and must have a non-positive total SRME impact over the course of a year, as described by the following equation:

$$\sum_t ((L_t^{H_2} - CFE_t) \times SRME_t) \leq 0 \quad (3)$$

The methodology used to calculate SRMEs in this paper is described in Supplementary Note 3.

We model system-level outcomes under each of these regimes for electrolysis facilities located in each of the six model zones shown in Figure 1. In all cases, all contracted clean resources must be new (aka 'additional') and must be sited in the local model zone, thereby ensuring deliverability to the electrolysis facility. We explore the impact of relaxing these constraints via cases where additionality requirements are explicitly removed, as well as cases where hydrogen producers are allowed to procure non-local generation (e.g. located in a different model zone than the electrolysis load) that may be physically non-deliverable due to transmission constraints. We also include cases varying the revenue from hydrogen sales (and by extension the electricity cost at which producers are willing to curtail electrolysis) and the total installed electrolyzer capacity to assess the sensitivity of outcomes to variability along these dimensions. We explore variations in the cost and embodied emissions from hydrogen production across each of these modeled scenarios.

3. Results

3.1. Hydrogen’s embodied emissions with no policy requirements

Model results indicate that both the attributional and consequential emissions intensities of hydrogen produced via electrolysis in a 2030 western US grid under a No Requirements policy are universally too large to meet statutory requirements for the full 45V PTC (Figure 2, left column). This outcome occurs despite a large expansion of clean generation across the Western Interconnection driven by IRA subsidies (Supplementary Figure 1). Attributional emissions intensities can be very large, up to 20 kgCO₂e/kgH₂ in model zones with high shares of coal-fired generation, but are notably small in the Pacific Northwest zone where hydropower is a majority of the energy mix. However, consequential emissions intensities are greater than 10 kgCO₂e/kgH₂ in all zones, and nearly 40 kgCO₂e/kgH₂ in the Wyoming & Colorado zone, suggesting that it would always be more environmentally friendly to produce the same amount of hydrogen using SMR rather than grid-based electrolysis. This consequential outcome occurs because the *marginal* generation used to serve any new hydrogen load always comes in large part from fossil resources. This is the case in every model zone, as demonstrated in Figure 3, which compares the generation portfolio procured to meet electrolysis load and actual system-level change in generation by technology resulting from the addition of the electrolysis load to the system for the same scenarios as Figure 2. Replacing the average emissions rate used in Eq. 1 with the SRME rate (as shown in Supplementary Figure 2) may therefore be a more accurate means of evaluating hydrogen’s true emissions impact from a 45V PTC compliance standpoint. Whereas hydrogen production with no accompanying clean energy procurements in the Pacific Northwest zone would qualify for the base PTC under an averages-based approach, it would not do so under a SRME-based approach.

We observe that the additional fossil electricity production used to supply new electrolysis load comes entirely from existing units, which are kept in service longer or operated at higher capacity factors to help meet the new electrolysis load than in the counterfactual without electrolysis. With sales revenue of at least \$3/kgH₂ due to the 45V PTC alone, hydrogen producers are incentivized to consume electricity at prices up to and exceeding \$60/MWh. The PTC thereby motivates hydrogen producers to operate their electrolyzers at very high utilization rates year-round, and to continue consuming electricity even when high-price resources like coal and gas are on the margin. Sensitivity cases indicate that embodied emissions from grid-connected hydrogen production are fairly insensitive to changes in the final sales revenue above the PTC threshold, with major outcomes nearly unchanged for hydrogen sales revenues in the \$3-5/kg range (Supplementary Figures 3-5). However, as shown in the same figures, outcomes are very different in cases without a PTC where hydrogen sales revenue is only \$1/kg. In these cases electrolyzers are only economical to operate when low-marginal-cost renewables or nuclear are on the margin, leading to very low consequential emissions from grid-based hydrogen production even under a No Requirements policy. The 45V PTC *itself*

therefore appears to be the primary driver of unfavorable emissions outcomes from grid-based hydrogen production in the US.

For significantly larger installed electrolyzer capacities (e.g. 5 GW), both attributional and consequential emissions intensities of grid-based hydrogen production decline somewhat (Supplementary Figure 6). In these cases, the large additional demand cannot be fully met by existing fossil generators, requiring significant amounts of new capacity to be deployed. Because clean resources are more competitive against new fossil resources than against existing ones, they make up a larger relative share of this new capacity (Supplementary Figure 7).

3.2. Emissions impact of a 100% Hourly Matching requirement

We find that enforcing a 100% Hourly Matching requirement (as described in Section 2.2) leads to zero attributional emissions and, in some cases, near-zero consequential emissions as well (Figure 2, columns two and three). Attributional emissions are effectively zero by definition in these cases, as electrolyzers never consume more electricity than is being concurrently and locally generated by clean resources. Hydrogen producers procure the mix of local clean generation and storage that is able to meet their demand cost-effectively in as many hours as possible (Figure 3 and Supplementary Figure 9). Operational profiles for hourly-matched electrolysis systems are shown in the left column of Figure 4 and Supplementary Figures 11-15, and illustrate how electrolyzers occasionally reduce consumption during periods of clean electricity scarcity to avoid drawing power from the grid mix.

While hydrogen production under a 100% Hourly Matching requirement therefore never *directly* consumes electricity from emitting resources, there are still scenarios in which it can have a high consequential emissions impact. This can occur through two mechanisms: first, via sales of excess clean electricity into the market, and second, via competition for limited high-quality clean resources. The comparison between 100% Hourly Matching outcomes in cases with and without excess sales permitted (Figure 2 and Supplementary Figure 6) indicates that it is primarily the second mechanism that leads to large consequential emissions impacts. We observe that sales of excess clean electricity play an unpredictable but secondary role, likely determined by the specific competing resources that these excess sales displace in the market. In cases without excess sales, the only interaction between hydrogen producers and the rest of the electricity system is through competition for limited renewable resource development. When high-quality renewable resources are scarce, procurement of these resources by hydrogen producers can lead other system users to rely on fossil resources, rather than lower-quality clean resources, to make up the difference. This phenomenon is illustrated in Supplementary Figure 10, which shows the modeled wind supply curve in the Wyoming & Colorado zone as well as the observed wind buildout in *both* the base case without electrolysis load *and* cases with 100% Hourly Matching of a 1 GW electrolysis load. When a portion of the highlighted high-quality resource is procured

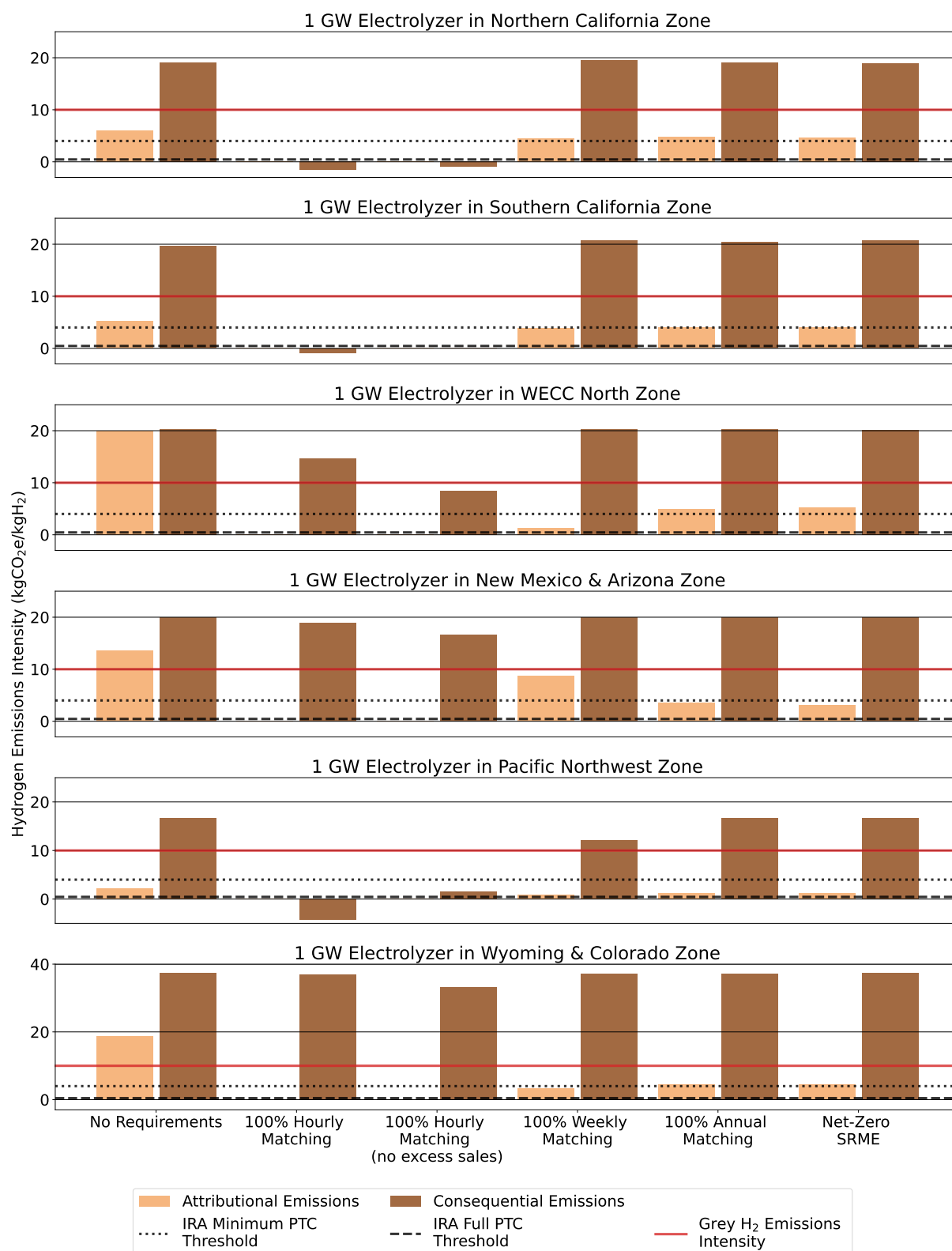


Figure 2. Attributional (left) and consequential (right) emissions rates from grid-based hydrogen production in each model zone (rows top-to-bottom) under a range of policy options (columns left-to-right).

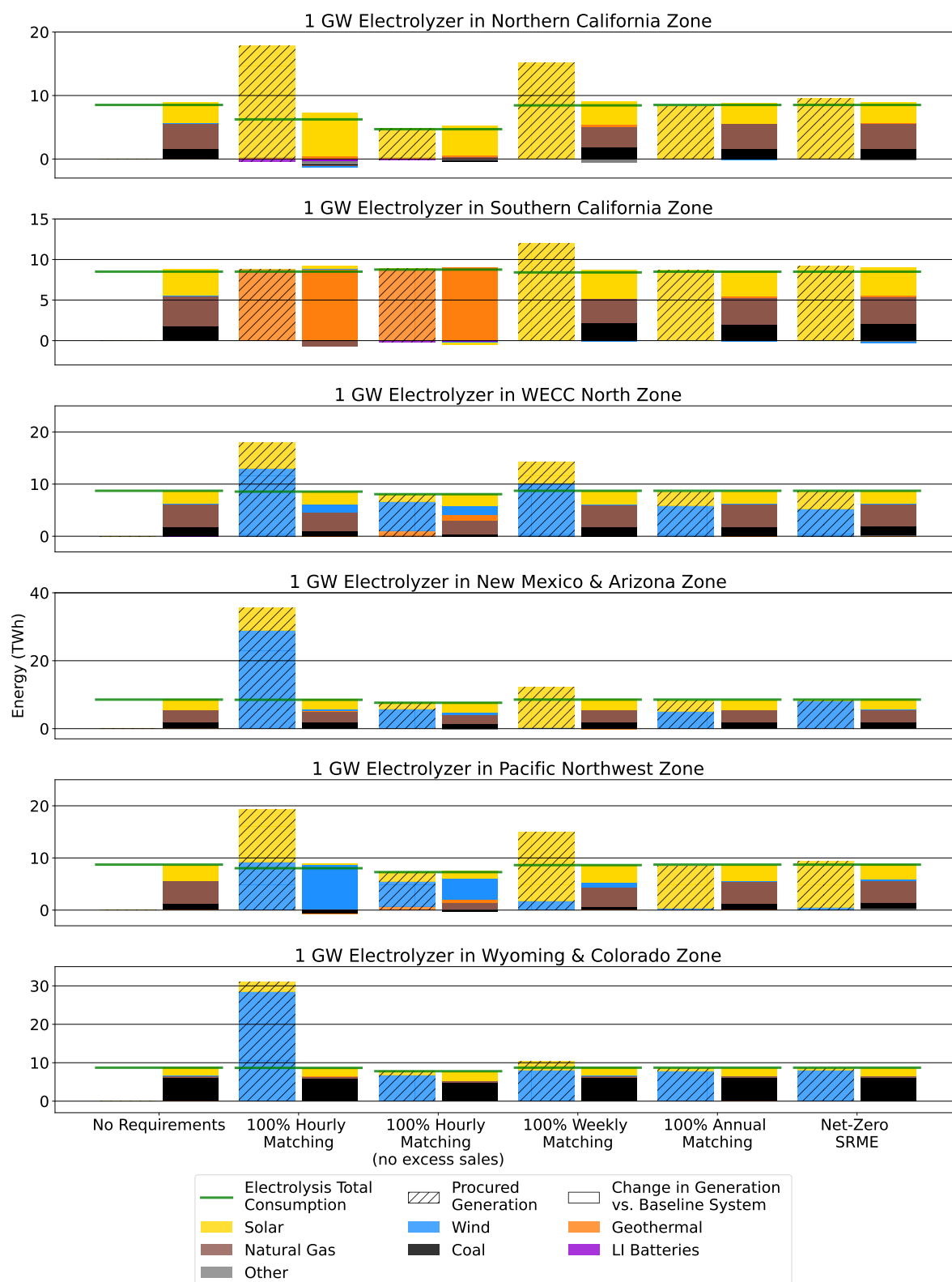


Figure 3. Total electricity consumption by hydrogen producers (green lines), compared with procured clean generation (left) and the actual observed changes in generation used to supply the additional hydrogen demand (right), under the same scenarios shown in Figure 2.

for hydrogen production and cannot be used for grid supply, the system chooses to retire less coal capacity rather than developing significantly more expensive wind resources in the next step of the step-wise approximation of the wind supply curve used in this study. As illustrated in the third column of Figure 3, these interactions occur primarily with wind resources, which generally have significantly more variance in quality and steeper supply curves than solar resources. Impacts of resource procurement the real world may be less stark than those observed here, as the step-wise supply curves used in the GenX model do not reflect the more continuous spectrum of real resource quality.

Although a 100% Hourly Matching requirement therefore cannot guarantee zero long-run emissions impact from hydrogen production, it does lead to consequential emissions outcomes that are universally superior to those under every alternative 45V PTC implementation investigated in this work, and often by wide margins. In several cases, a 100% Hourly Matching requirement reduces consequential emissions to near-zero when they would be worse than those of SMR under any alternative policy. These benefits are more pronounced in scenarios with greater total hydrogen production, as illustrated in Supplementary Figure 6. A 100% Hourly Matching requirement is therefore likely to be the best practical means of minimizing the real emissions impact of grid-based hydrogen production in the US. It should be noted that this requirement (in combination with deliverability and additionality requirements, as discussed in Sections 3.4 and 3.5) also ensures consequential emissions outcomes no worse than those from hydrogen production supplied exclusively by behind-the-meter carbon-free resources. Like grid-supplied clean generation under an hourly matching requirement, behind-the-meter clean generation both competes for high-quality renewable resource sites that could instead supply power to the grid and can influence system-level emissions outcomes positively or negatively by exporting excess clean generation to the grid. The large consequential emissions impacts observed in some of our modeled cases are therefore a potential consequence of *any* electrolysis-based hydrogen production in the current US policy environment. Possible approaches to mitigating these negative outcomes through updated federal policy are discussed in Section 4.

3.3. Emissions impacts of alternative 45V PTC implementations

We find that the three potential alternatives to a 100% Hourly Matching standard investigated in this work, 100% Weekly Matching, 100% Annual Matching, and Net-Zero SRME, are universally ineffective at reducing consequential emissions from grid-based hydrogen production (Figure 2 and Supplementary Figure 6, columns 4-6). In some cases they do achieve reduced attributional emissions rates, though only insofar as they lead hydrogen producers to directly reduce consumption of grid power in hours when carbon-free generation is plentiful. Importantly, these three alternative strategies differ from 100% Hourly Matching in that they allow hydrogen producers to *offset* net consumption of grid electricity in some hours with excess production of clean electricity in others. As shown in Figure 4 and Supplementary Figures 11-17, producers

typically meet these requirements by running their electrolyzers at high utilization rates year-round while procuring enough of the cheapest local renewable generation to fully offset their use in terms of the relevant metric—either megawatt-hours for Weekly and Annual Matching or marginal emissions for Net-Zero SRME. The compliance strategy of procuring the cheapest available renewable electricity in bulk, regardless of the timing of this generation, is remarkably consistent across the three policy cases. However, as illustrated in Figure 3 and Supplementary Figure 7, this excess procurement almost never translates into real changes in the energy mix. The actual new generation used to meet new hydrogen load is instead almost identical to that observed in the No Requirements cases. This is true even for scenarios where procurement made under a 100% Hourly Matching requirement *does* successfully translate into actual changes in generation.

The general ineffectiveness of these ‘offsets’ based approaches as an emissions mitigation strategy is explained by the anticipated evolution of US electricity markets in a post-IRA world. The economic impetus provided by IRA subsidies leads clean electricity penetration in our modeled systems to far exceed levels mandated under current state policies by 2030. In this scenario the market for state-level policy compliance EACs is fully saturated, so simply adding demand for clean electricity attributes does not provide any economic incentive to increase supply. Instead, hydrogen producers are able to pay effectively zero to procure excess clean power from generators *that would already have been built*. These observations suggest that hydrogen producers should be considered fully responsible for any emissions induced by direct consumption of grid electricity, and that offsets should not be considered a credible means of eliminating the embodied emissions of hydrogen electrolysis.

3.4. The importance of deliverability

We find that allowing resource procurement over large geographic areas can lead to significant consequential emissions from hydrogen production even when a 100% Hourly Matching requirement would otherwise ensure low consequential impact, as the introduction of transmission constraints prevents physical delivery of procured clean electricity. Transmission congestion can lead to different marginal generating units supplying power on each side of a constrained pathway, and persistent congestion can affect capacity retirements and additions in the long run. Consumption and production on different sides of frequent transmission constraints can thus lead to divergent emissions impacts. We demonstrate this through a set of controlled test cases (Supplementary Figure 18) where we show that allowing hydrogen production in each of two model zones using local solar power with a 100% Hourly Matching requirement leads to zero or negative consequential emissions impact, but allowing production in one zone using solar procured from the *other* zone leads to a very large consequential impact. In the case with non-local procurement, transmission constraints lead to the hydrogen producer consuming local fossil generation in some hours even while claiming

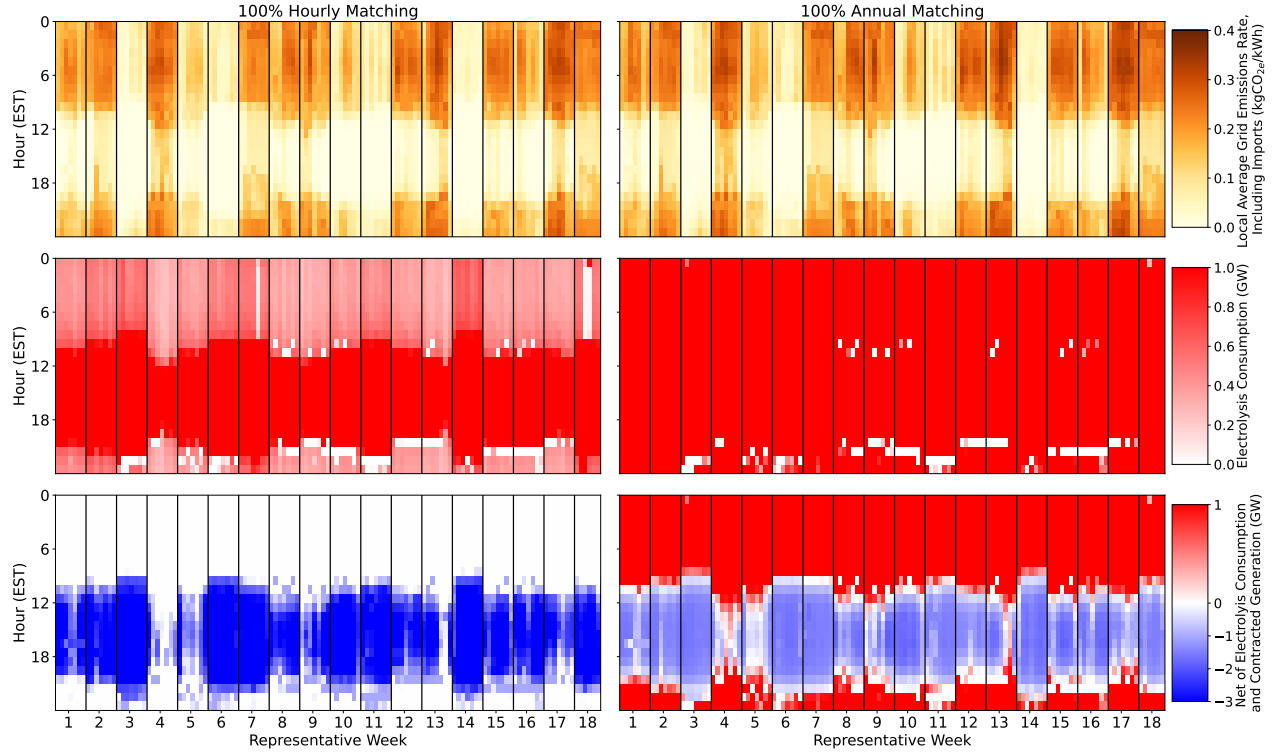


Figure 4. Time series data showing local average grid emissions, including imports (top), hydrogen electrolysis electricity consumption (middle), and electrolysis consumption minus procured clean generation (bottom), for both 100% Hourly Matching and 100% Annual Matching policies in the scenario with 1 GW installed electrolyzer capacity in the Northern California model zone.

full matching.

This finding demonstrates that clean resources subject to transmission constraints that prevent delivery of the procured energy cannot be relied on to eliminate emissions from hydrogen production. In this study, the deliverability condition is operationalized by requiring procurement of clean electricity from within the local model zone. However, unlike the model system studied in this work, the real grid is not divided neatly into well-connected zones with perfect internal deliverability, and transmission bottlenecks of varying severity exist at all spatial scales. When implementing a 100% Hourly Matching requirement for grid-based hydrogen production, prior determination of qualifying grid regions within which transmission constraints are minimized could help to mitigate instances of non-deliverable procurement. If these regions are internally well-connected, then locality (i.e. procurement from within the same region) could stand in as a reasonably proxy for deliverability. A more robust deliverability enforcement mechanism could instead rely on real-time monitoring via existing metrics like locational marginal electricity prices (LMPs), which diverge when congestion exists between two points in the electricity grid. Under this system, grid-based hydrogen production would be allowed to claim use of a non-located clean resource only during periods when the LMPs at the point of generation and point of delivery show that the procured energy is

physically deliverable.

3.5. The need for additionality

In our baseline scenarios we assume that only new clean resources (i.e. not in operation at the beginning of the model planning period) may be procured to meet a 100% Hourly Matching requirement for grid-based hydrogen production. We additionally assume that resources used to meet state capacity installation mandates (e.g. California’s recent 1 GW clean baseload procurement order [24]) cannot also be counted towards clean hydrogen production. In modeled scenarios cases where we remove each of these requirements individually (see Supplementary Figure 19), we find that a 100% Hourly Matching requirement loses all of its consequential impact. This is because contracts with existing or mandated clean energy resources have no causal impact on the continued operation of these resources in the electricity system as long as they are not under threat of economic retirement. Any credible implementation of the 45V PTC that allows grid-based hydrogen production to qualify for subsidies should therefore enforce strict additionality requirements, bounding the installation dates of resources that can be counted toward clean hydrogen production and considering overlap with state-level capacity procurement mandates. Minor exceptions to this rule may be acceptable, specifically in the case of existing plants that would be forced to retire or curtail their generation without offtake agreements from hydrogen producers.

While existing and mandated resources can therefore be considered non-additional due to their lack of causal linkage to procurement by hydrogen producers, this definition could be extended to encompass even *new, non-mandated* resources that would have been built with or without having being procured for hydrogen production specifically. For example, the procurement of high-quality wind resources discussed in Section 3.2 could be considered non-additional under this definition, as those resources would have been deployed regardless due to their economic favorability. In fact, by specifically banning procurement of these high-quality wind resources for hydrogen production (Supplementary Figures 20 and 21), we can significantly improve the observed consequential emissions outcomes. 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.

3.6. Impact of policy choices on the cost of clean hydrogen

Enforcing a 100% Hourly Matching requirement leads to moderately increased costs for grid-based hydrogen production in some cases. Figure 5 shows the LCOH of hydrogen produced in the system under the same scenarios shown in Figures 2 and 3, for installed

electrolyzer system costs of \$1200/kW (reflecting current costs), \$600/kW (a ‘moderate’ possible cost in 2030), and \$300/kW (a ‘low’ possible cost in 2030) [12, 13]. LCOH outcomes are fairly consistent across modeled regions, and are nearly identical among non hourly-matched cases.

The observed differences in cost between cases with No Requirements and 100% Hourly Matching indicate that enforcing a 100% Hourly Matching requirement generally adds \$0-1/kgH₂ to the LCOH. The additional costs can be near-zero when clean firm resources like geothermal power are available for procurement. Even in regions where only wind, solar and batteries can be relied on, the additional cost of 100% Hourly Matching is not substantial. Costs are somewhat greater when excess sales are forbidden, or when the total hydrogen production is larger (leading to procurement of clean generation from ‘higher’ up the supply curve; Supplementary Figure 8). For sales prices of \$1/kg or greater, which would slightly undercut conventional grey hydrogen, and assuming an additional \$3/kg PTC, clean hydrogen producers in all regions would likely break even or make a profit on their investments as long as electrolyzer costs continue to decline [12, 13]. The US Clean Hydrogen Strategy and Roadmap suggests that there may be large markets for clean hydrogen in the US at sales prices well above \$1/kg [7], which could serve as viable initial markets even at current electrolyzer costs.

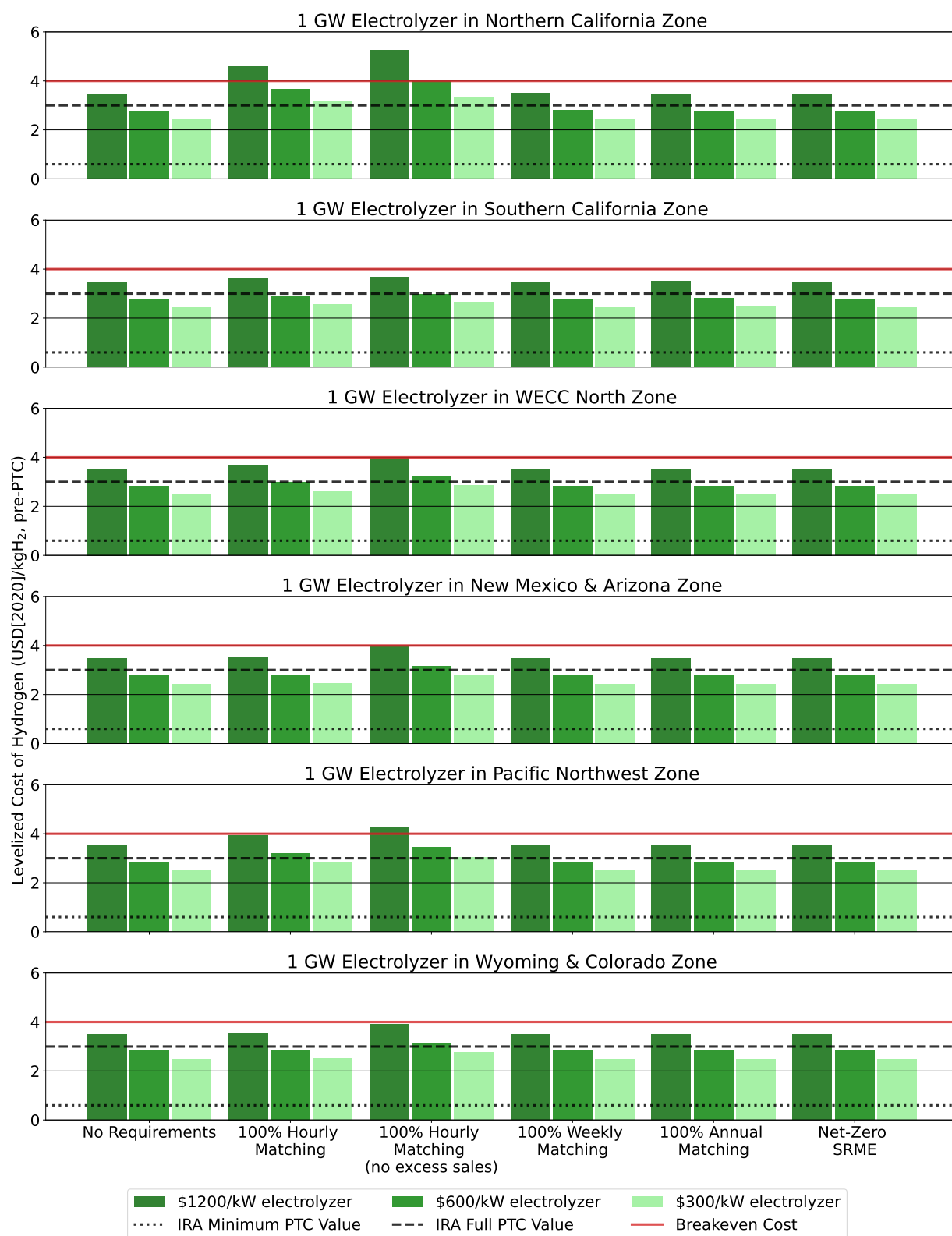


Figure 5. Levelized cost of hydrogen (LCOH) for the same scenarios shown in Figures 2 and 3, compared with potential revenues from sales. LCOH values are provided for a range of potential electrolyzer capital costs.

4. Discussion and Conclusion

In this study we have used capacity expansion modeling to demonstrate a system of clean energy procurement that could be used to determine qualification for the 45V clean hydrogen PTC in the US. By requiring hydrogen producers to match their grid electricity consumption with deliverable, additional, and carbon-free generation on an hourly basis, regulators can ensure that hydrogen is produced at effective emissions rates equivalent to those of behind-the-meter installations and lower than all other procurement strategies considered herein. We demonstrate that each component of the proposed requirement - deliverability, additionality, and hourly matching - is critical to minimizing the system-level emissions impact of grid-based hydrogen production. By enforcing all three, regulators can ensure that grid-based hydrogen production produces no emissions from direct consumption of fossil-fired electricity (zero attributional emissions) and impacts system-level emissions to no greater a degree than electrolysis supplied exclusively by behind-the-meter carbon-free generation.

We find that meeting a 100% Hourly Matching requirement will come at a minor additional cost to hydrogen producers compared to alternative options, but that the full 45V PTC subsidy will likely be large enough to support investment even with the additional cost of compliance. A 100% Hourly Matching requirement meeting deliverability and additionality conditions can therefore enable economically-competitive grid-based hydrogen production while simultaneously minimizing emissions impacts. Our analysis assumes only clean energy technologies that are currently commercially mature are available for procurement. Commercialization of emerging clean technologies that are better suited to serving 24/7 load (e.g. advanced nuclear, enhanced geothermal, or long-duration energy storage) could further reduce the additional cost of an hourly matching requirement [23, 31].

The logistics of implementing a strict 100% Hourly Matching requirement may initially be challenging, as markets for time-based PPAs or EACs are just emerging in response to demand from voluntary corporate, government, and institutional actors [32–34]. Implementation of the 45V PTC or similar ‘green’ hydrogen subsidies could thus permit projects to qualify by directly consuming carbon-free generation behind-the-meter and/or by demonstrating time-based matching of electrolyzer consumption with new, locally-procured, carbon-free generation. While initial projects may opt to pursue purely behind-the-meter supply, the rapidly improving maturity of accounting standards, protocols, and market mechanisms for creation, tracking, and trading of time-based energy attribute certificates (T-EACs) will quickly unlock additional opportunities to demonstrate near-zero embodied emissions from grid-connected electrolysis. The large financial incentive provided by the 45V PTC can also help to accelerate maturation of markets and standards for time-based energy accounting in the United States.

Although the modeling work presented in this paper found that an hourly matching requirement with deliverability and additionality conditions consistently minimized long-run emissions impacts relative to alternative 45V PTC implementations, it also

showed that *any* electrolysis-based hydrogen production in the US could substantially increase long-run electricity system-level emissions by ‘using up’ high-quality renewable electricity resources. These negative impacts could presumably be exacerbated if permitting or transmission interconnection bottlenecks further limit the growth of clean generation over the coming decade. Additional near-term emissions may be considered a necessary cost of encouraging early electrolyzer deployment in order to address concerns regarding the feasibility of scaling up clean hydrogen supply to meet future goals [35]. These competing interests could ideally be balanced by directing hydrogen production toward end uses with maximum emissions abatement potential and avoiding it where direct use of clean electricity would reduce emissions by a greater amount [36]. A policy mechanism that explicitly prioritizes system-wide emissions reductions, such as a carbon pricing or cap-and-trade program, could help encourage climate-positive outcomes alongside electrolysis deployment by financially disincentivizing electricity consumption in hours when fossil plants are on the margin and directing hydrogen production toward end uses with the greatest overall decarbonization potential. A cap-and-trade program in particular would likely mitigate the need for further hydrogen-specific regulations by ensuring that system-wide emissions cannot increase as a result of electrolysis operation. A simpler reform more in line with current US policy could involve replacing the 45V PTC with a comparably-sized electrolyzer *investment* tax credit, thereby removing the strong financial incentive to continue hydrogen production even during periods when electricity prices are high and fossil plants are on the margin (as discussed in Section 3.1). Barring these or similar legislative reforms, a standard for hourly matching of electricity consumption with deliverable, additional clean generation is likely the best practical means of minimizing emissions impacts from electrolysis-based hydrogen production in the current US policy environment.

Acknowledgements

This work was funded by Princeton University’s Low-Carbon Technology Consortium, which is funded by gifts from Google, GE, and ClearPath.

Author Contributions

W.R. and J.D.J. conceptualized the study. Q.X. developed the 24/7 CFE procurement model framework, and W.R. adapted it to study grid-based hydrogen production. W.R. performed the formal analysis visualization and investigation, and produced the figures. Q.X. and J.D.J. provided oversight. W.R. drafted and finalized the manuscript. J.D.J. reviewed and edited the manuscript.

Ethics Declarations

J.D.J. is part owner of DeSolve, LLC, which provides techno-economic analysis and decision support for clean energy technology ventures and investors. He serves on the advisory board of Eavor Technologies Inc., a closed-loop geothermal technology company, and has an equity interest in the company. He also provides policy advisory services to Clean Air Task Force, a non-profit environmental advocacy group, and serves as a technical advisor to MUUS Climate Partners and Energy Impact Partners, both investors in early stage climate technology companies.

Data Availability

All GenX input and results data relevant to this work are available at Ricks et al. [26]. The 24/7 CFE procurement model used in this study is available from the authors upon reasonable request, and will be included in an upcoming release of GenX [21].

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