Enabling grid-based hydrogen production with low embodied emissions in the United States

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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 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 clean resources can guarantee compliance with emissions thresholds, the PTC could also be structured to allow producers using grid electricity to qualify subject to certain clean energy procurement requirements. In this work we model the evolution of the power sector in the western United States through 2030 to assess the emissions impact of the clean hydrogen PTC under multiple possible implementations. We find that with no requirements for grid-connected hydrogen producers to procure clean electricity, embodied emissions from hydrogen produced via electrolysis in California are worse than those from hydrogen produced via conventional, unabated fossil pathways. By contrast, requiring producers to match 100% of their electricity consumption on an hourly basis with locally-procured, 'additional' clean generation ensures embodied emissions rates equivalent to those of behind-the-meter installations. Failure to meet requirements for hourly matching, locality, or additionality of procured clean generation can result in significant excess emissions. Added hydrogen production costs from enforcing an effective 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 CO_2-equivalent for every kg of H_2 produced [9, 10]. 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, 11]. Electrolysis is currently the more expensive method of production, with estimated costs on the order of \$5-6/kgH_2 compared with \$1-3/kgH_2 for fossil pathways at historical natural gas prices [10], but is projected to become significantly cheaper as the costs of clean electricity and electrolyzers decline [11, 12].

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) [13]. Hydrogen produced through a process with less than 4 kgCO_2e/kgH_2 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 kgCO_2e/kgH_2. The new PTC will be particularly relevant for hydrogen produced via electrolysis, which can achieve near-zero lifecycle emissions when using carbon-free electricity inputs [7, 14]. 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/kgH_2 using 100% gas-fired electricity ($\sim$0.4 kgCO_2/kWh [15]) would produce hydrogen at an embodied emissions rate of roughly 20 kgCO_2e/kgH_2, 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 PTC qualification [13]. For all hydrogen production pathways, including electrolysis, GREET requires users to determine the generation mix supplying any electricity inputs [14]. 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 U.S. generation mix, embodied emissions from grid-connected electrolysis would be far too high to meet statutory requirements for even the minimum PTC [7, 15].

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 [16, 17], 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 clean hydrogen PTC.

In this paper we present a possible implementation of 45V 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 locally-procured 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 PTC implementations that relax requirements for hourly matching, locality, or additionality. The aim of this work is to support ongoing IRA implementation efforts by providing a quantitative analysis of the conditions under which grid-based hydrogen production can reliably meet the embodied emissions thresholds necessary to qualify for the 45V production tax credit.

2. Methods

In this study we use the GenX electricity systems capacity expansion planning model to evaluate the emissions impacts of subsidized hydrogen production via grid-connected electrolysis under a set of possible 45V PTC eligibility requirements [18, 19]. 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 U.S. 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 U.S. 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 [20] and are described in greater detail in Xu et al. [21]. Only currently mature, commercially-available gridscale generation and storage technologies are assumed to be available for deployment by 2030. Geothermal inputs have been adjusted from Xu et al. [21] to reflect updated state policies and resource estimates [22, 23]. 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. [24].

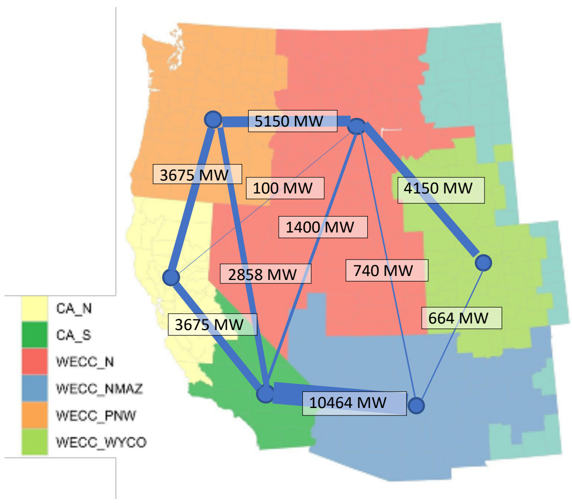

Figure 1. Illustration of the modeled U.S. Western Interconnection electricity system and its component zones, which represent single regions or aggregations of regions from the EPA's Integrated Planning Model [25]. California is divided into two model zones. Existing interregional transmission capacities 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 the southern California 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 PPAs or EACs) to meet any imposed policy requirements. We evaluate the emissions intensity of this hydrogen production via two approaches [26]:

(i) **Attributional Emissions:** The share of total local grid emissions that would be attributed to hydrogen production under an averages-based accounting approach, similar to EPA Scope 2 accounting guidance [27]. The attributional emissions intensity of hydrogen produced is calculated as:

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

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. [21]), and H_2^{Tot} is the total hydrogen production in the system.

(ii) **Consequential Emissions:** The true 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:

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

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.

In addition to emissions rates we also assess the impacts of possible PTC implementations on the cost of hydrogen production. The levelized cost of hydrogen (LCOH), the total revenue per unit of hydrogen sold needed to make up all associated costs, is calculated as:

$$LCOH = (\frac{CAPEX \times (FOM + CRF) + C_{grid}}{CF \times 8760} + \frac{C_{el}^{Tot}}{H_2^{Tot}})/Eff_{el}^{H_2} \tag{3}$$

where $CAPEX$ is the total installed capital expenditure per kW of the electrolyzer system, FOM is the total fixed O&M costs given as an annual percentage of CAPEX, CRF is the capital recovery factor, C_{grid} is the cost of a transmission-level grid connection, CF is the electrolyzer capacity factor, C_{el}^{Tot} is the total cost of sourcing input electricity, and $Eff_{el}^{H_2}$ is the electrolyzer efficiency. Values for these and other input parameters are provided in Table 1. We calculate the cost of input electricity as:

$$C_{el}^{Tot} = \sum_t (L_t^{H_2} \times P_t) + (C_{NE} + C_{TL} - R_C + C_{ESR} + C_{Bat} + C_{CFE}) \times H_2^{Tot} \tag{4}$$

where P_t is the local price of bulk electricity (including generation and capacity costs) at timestep t, C_{NE}, C_{TL}, R_C, and C_{ESR} are the hydrogen producer's shares of the local cost of network expansion, transmission loss cost, congestion revenue, and cost of compliance with state energy share requirement policies, respectively, C_{Bat} is the cost of onsite battery storage, and C_{CFE} is the cost of purchasing EACs to meet any hydrogen-specific policy requirements. This cost formula assumes that all clean energy purchases are in the form of EACs. Costs with long-term PPAs will be less than or equal to the costs with EACs, as procurers may be able to capture excess generator rents in the form of lower PPA prices or secure lower average purchase price by providing generators with greater revenue certainty [21].

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)	$/kg$H_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 [28], 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 PTC. The minimum sales revenue assumes that hydrogen is sold to the end consumer at $0/kg.

2.2. Policy Scenarios

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

(i) **No Requirements:** Electrolysis demand is added to the grid without any required offsets beyond existing state policies, and is met by the economically optimal 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. Procured resources must be new (aka 'additional') and must be sited in the local model zone. This policy and its formulation in GenX are described in detail in Xu et al. [21], where it is referred to as '24/7 CFE.' Here any EACs procured must be time-based, or T-EACs. We assume by default that hydrogen producers can sell any excess procured carbon-free generation back to the grid, reducing their overall costs. We include sensitivity cases where no excess sales are permitted.

(iii) **100% Annual Matching:** Hydrogen producers are required to procure enough carbon-free electricity production to completely offset their annual consumption. This procurement strategy is commonly employed today in voluntary markets and for compliance with state policies (e.g. renewable portfolio standards), and we present the attributional and consequential emissions of this approach for comparison purposes.

We also model a set of alternative policy variants that relax requirements on qualifying resources, including cases that alter the definition of the 'local' zone to include the entire Western Interconnection, allowing hydrogen producers to procure resources over large geographic distances to meet the imposed matching requirements, as well as cases where additionality requirements are explicitly removed. In addition to these policy-focused cases we also vary 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 variations along these dimensions. We explore variations in the cost and embodied emissions from hydrogen production across these modeled scenarios.

3. Results

3.1. Hydrogen's embodied emissions with no policy requirements

Model results indicate that the emissions intensity of hydrogen produced via electrolysis in a 2030 California grid under a No Requirements policy is too large to meet statutory requirements for the clean hydrogen PTC. With no mandate for clean energy procurements, both attributional and consequential emissions from grid-based hydrogen production are greater than even the minimum PTC threshold (see Figure 2). This is despite significant clean energy expansion leading to 80% annual clean generation in the southern California grid. Consequential emissions from grid-based electrolysis are roughly double those of grey hydrogen. As shown in the leftmost column Figure 3, the presence of an additional hydrogen load in the system incentivizes a mix of additional generation consisting of some renewables, but nearly equal amounts of gas and coal. With sales revenue of \$3/kgH_2 or greater due to the PTC, hydrogen producers are incentivized to continue consuming electricity even at prices up to \$60/MWh or more. These prices are well above the thresholds at which coal and gas become marginal generators in the system. As California's electricity mix is likely to be cleaner than the national average by 2030 [29], it is probable that the emissions impact of hydrogen production from bulk grid electricity (i.e., without new clean generation dedicated to supply hydrogen production) would be even larger nationally.

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 consistently low hydrogen emissions intensities. As shown in the three central columns of Figure 2, attributional and consequential emissions rates are generally near-zero or negative under a 100% Hourly Matching regime across a range of sensitivity cases. Procured generation in 100% Hourly Matching cases very closely matches the actual observed change in the generation mix due to electrolyzer consumption (Figure 3), demonstrating that hydrogen producers are effectively procuring the *additional* carbon-free generation needed to match their demand at all times. As shown in Figure 4, the only operational electricity system impact of hydrogen production under a 100% Hourly Matching requirement is through sales of excess clean electricity. Hydrogen producers never consume more electricity than is being locally generated by procured clean resources, thereby eliminating any incentive for additional production from emitting marginal generators in the local grid.

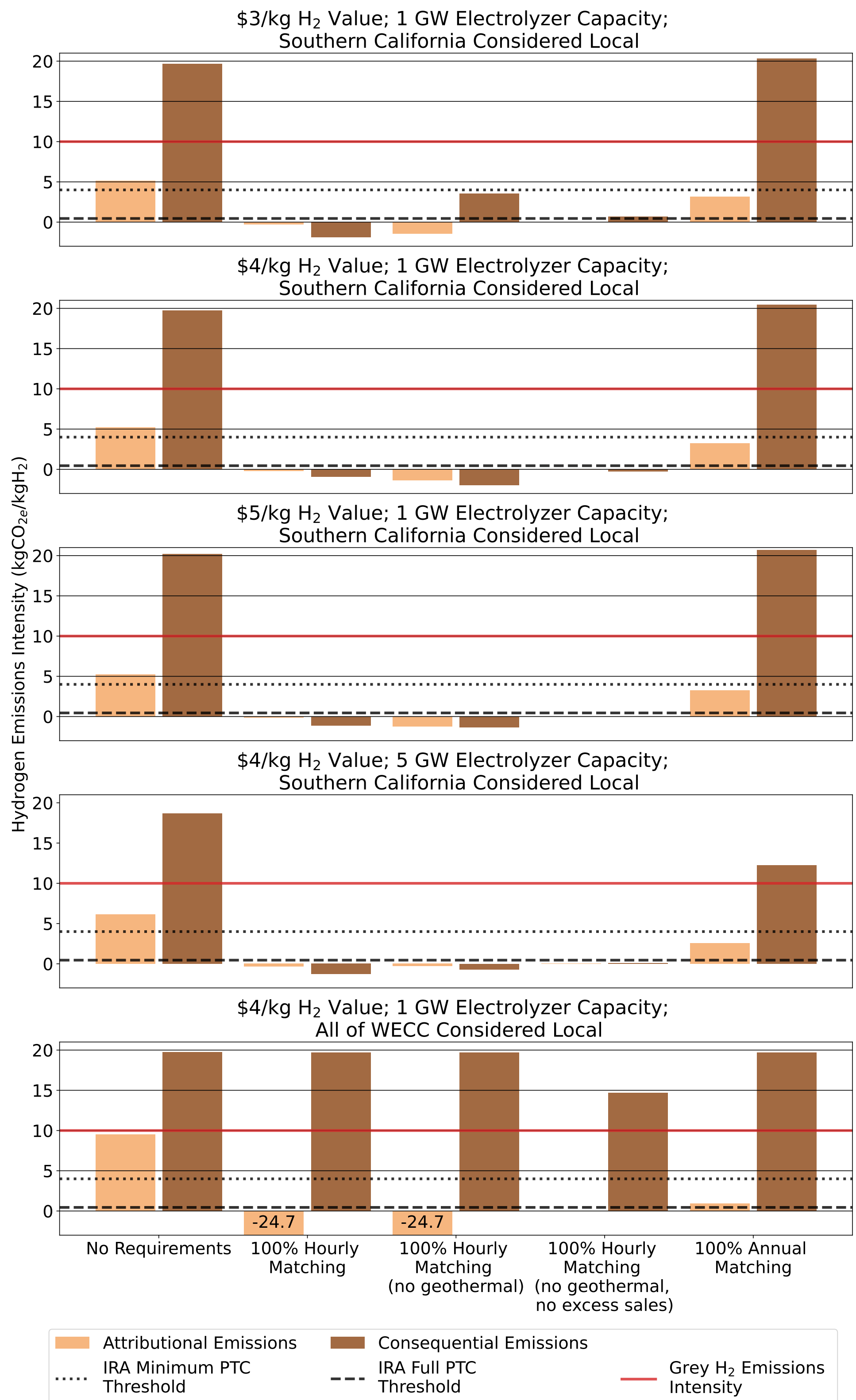

Figure 2. Attributional (left) and consequential (right) emissions rates from grid-produced hydrogen under a range of policy options and sensitivity scenarios.

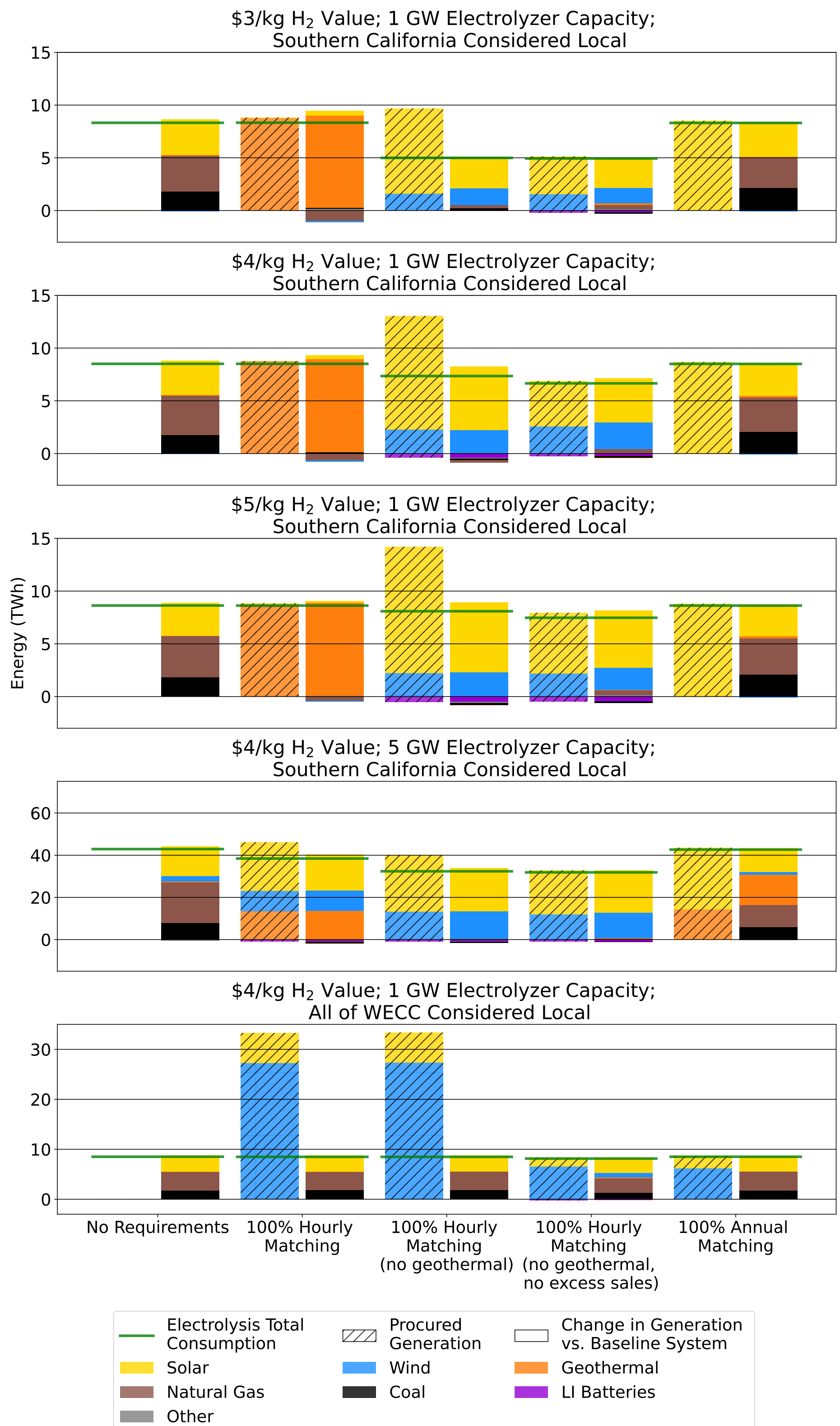

Figure 3. Total electricity consumption by hydrogen producers (green lines), compared with procured clean generation (left) and the actual observed changes in generation used to supply the additional hydrogen demand (right), under the same scenarios shown in Figure 2.

Hydrogen production under a 100% Hourly Matching requirement can still have non-negative consequential emissions due to the indirect impacts of clean energy procurements and sales. In one observed case where hydrogen producers are allowed to sell excess clean electricity to the grid, market interactions resulting from these sales lead to greater coal generation in another model zone. This may be a consequence of shifting clean energy production into the southern California zone in order to meet local procurement requirements, which reduces clean generation in other zones relative to the baseline scenario and increases the market niche for coal in those zones. Even without excess sales allowed (Figures 2 and 3, column four), hydrogen producers can still have a small indirect impact on system emissions by procuring capacity-limited high-quality renewable resources that would otherwise be used to generate electricity for the grid. However, it should be noted that both of these indirect effects can also occur when hydrogen is produced using behind-the-meter clean resources. Behind-the-meter clean generators could theoretically sell power to the grid when generation exceeds local electrolysis demand, and the choice to develop these resources for hydrogen production necessarily prevents them from being fully utilized for commercial electricity generation. It would therefore be inconsistent to penalize only grid-connected electrolysis on the basis of these indirect impacts.

3.3. The importance of local procurement

Allowing resource procurement over large geographic areas may result in significant differences in both attributional and consequential emissions. Transmission congestion leads to different marginal generating units supplying power on each side of the constraint, while persistent grid 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. Herein we see significant consequential emissions from hydrogen production when large transmission constraints are present, even if 100% Hourly Matching is enforced. In modeled scenarios where all of the Western Interconnection is considered 'local', allowing the hydrogen producers in southern California to (for example) procure wind power in Wyoming to meet their requirements, a 100% Hourly Matching policy cannot guarantee low emissions intensities (see Figures 2 and 3, bottom row). Here, when interregional transmission corridors are congested, procured non-local resources simply displace other clean options in their own grid regions while local fossil resources provide the additional generation needed to meet additional hydrogen demand in southern California.

This finding implies that resources subject to significant transmission constraints (relative to the electrolyzers' point of interconnection) cannot be relied on to eliminate emissions from hydrogen production. However, unlike the model system used here, the real grid is not divided neatly into well-connected zones, 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

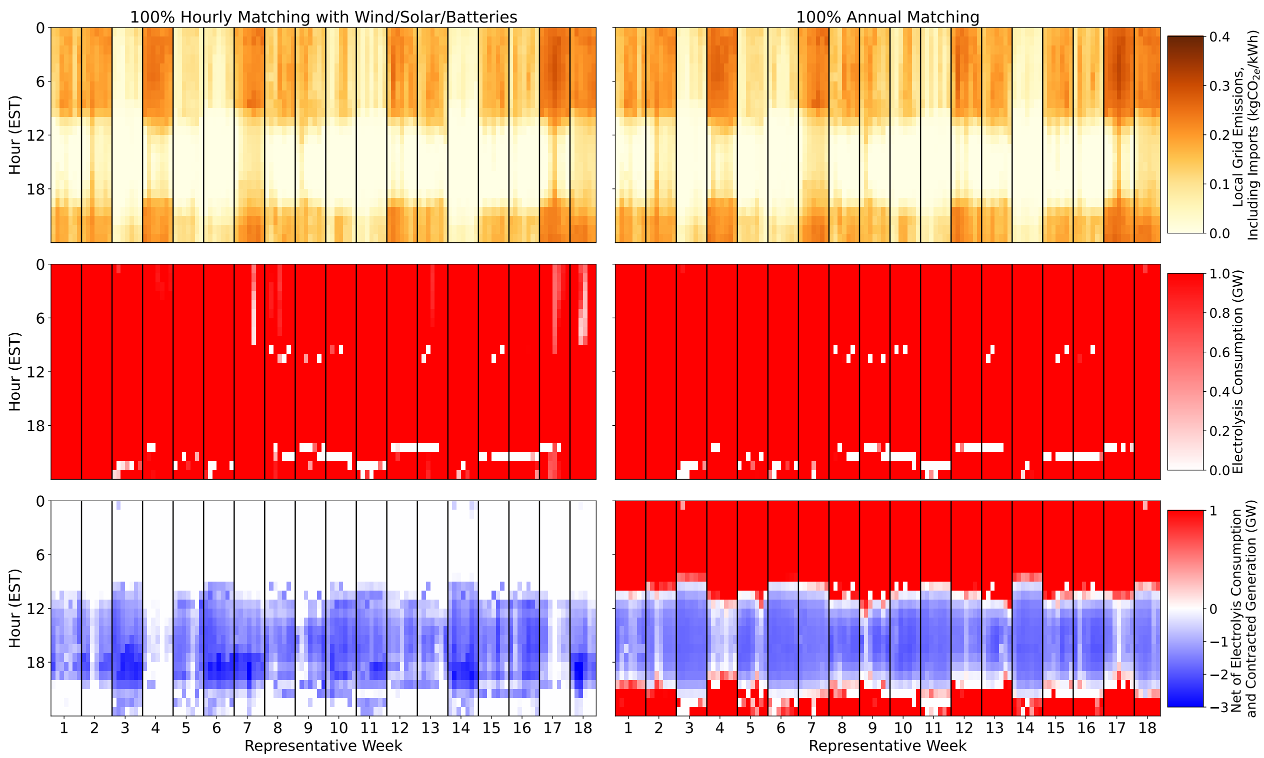

Figure 4. Time series data showing local average grid emissions, including imports (top), hydrogen electrolysis electricity consumption (middle), and electrolysis consumption minus procured clean generation (bottom), for both 100% Hourly Matching and 100% Annual Matching scenarios. Electrolyzers run at high capacity factors in both scenarios due to the large financial incentive provided by the PTC. Grid emissions rates are generally much higher at night, while excess procured generation occurs during daytime hours.

qualifying grid regions within which transmission constraints are minimized could help to mitigate procurement across frequently-congested corridors. A more robust 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-colocated 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.

3.4. 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 [22]) cannot also be counted towards clean hydrogen production. In modeled scenarios cases where we remove each of these requirements individually, we find that a 100% Hourly Matching requirement does nothing to reduce the emissions intensity of hydrogen production compared to the No Requirements scenario. 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 45V 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.

3.5. Emissions impact of a 100% Annual Matching requirement

We find that enforcing a relaxed requirement for 100% Annual Matching of electrolysis demand with carbon-free electricity supply does little to nothing to eliminate hydrogen's embodied emissions in the southern California example case. In scenarios where only 100% Annual Matching is required, attributional emissions fall only slightly and consequential emissions can even increase relative to simply purchasing bulk electricity (see Figure 2). In the worst cases the system-wide emissions impact of hydrogen production with 100% Annual Matching is double that of grey hydrogen, and more than 40 times the threshold needed to claim the full PTC. As shown in the rightmost column of Figure 3, hydrogen producers required to match 100% of their annual demand typically do so with solar power, the lowest-cost carbon-free energy source available in the region. Despite these procurements, the actual additional generation mix used to meet the additional hydrogen demand in the system is nearly identical to that of the No Requirements case. This is to say, the 100% Annual Matching clean energy procurements provide nearly zero actual additionality. With IRA tax credits for carbon-free generation and storage, clean energy deployment in the Western Interconnection in 2030 significantly exceeds requirements set by state-level clean energy standards. System-wide markets for EACs are therefore highly saturated, and additional EAC demand from hydrogen producers is not enough to change this. The local procurement requirement does add a significant amount of new clean generation in the southern California zone, and this new capacity may meet common definitions for 'additionality.' However, capacity expansion modeling herein illustrates that this new capacity simply displaces roughly equal amounts of clean generation that would have otherwise been deployed elsewhere in the system.

Even 100% Annual Matching clean energy procurements that could achieve full additionality may not completely offset emissions induced by electrolysis demand. The attributional emissions accounting methodology used here effectively assumes complete additionality, but attributional emissions rates are still significantly greater than the full

PTC threshold even with 100% Annual Matching. This is because average grid emissions are generally much higher during times when hydrogen demand exceeds procured clean supply than they are during times when the opposite is true (see Figure 4). Procured solar generation is delivered primarily during the midday solar peak, when local grid emissions rates are often zero.

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

Enforcing stricter clean energy matching requirements leads to moderately increased hydrogen costs. 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) [11, 12]. Across all scenarios we find that the large PTC incentivizes hydrogen producers to maintain production even when electricity prices are high, leading to greater overall levelized costs.

The observed differences in cost between cases with No Requirements and 100% Hourly Matching show that enforcing a 100% Hourly Matching requirement generally adds \$0-1/kgH_2 to the LCOH. The additional costs are much lower when clean firm resources like geothermal power are available for procurement. Even in scenarios where only wind, solar and batteries can be relied on, as may be the case in various U.S. grid regions, the additional cost of 100% Hourly Matching is not substantial. 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 are likely to break even or make a profit on their investments as long as electrolyzer costs continue to decline. The U.S. Clean Hydrogen Strategy and Roadmap suggests that there may be large markets for clean hydrogen in the U.S. at sales prices well above \$1/kg [7], which could serve as viable initial markets even at current electrolyzer costs.

It should be noted that the LCOH calculations in this study use fairly conservative financial assumptions, including a 10-year capital recovery period equal to the 45V PTC duration. The costs shown in Figure 5 are for producers in southern California, where costs for new generation and transmission are higher than nearly any other grid region in the country [28, 30]. The large \$85/kWyr electrolyzer grid interconnection fee assumed in this study alone increases LCOH by roughly \$0.50/kgH_2. It is therefore likely that grid-based hydrogen production in U.S. grid regions outside of southern California will have lower levelized costs than those shown here.

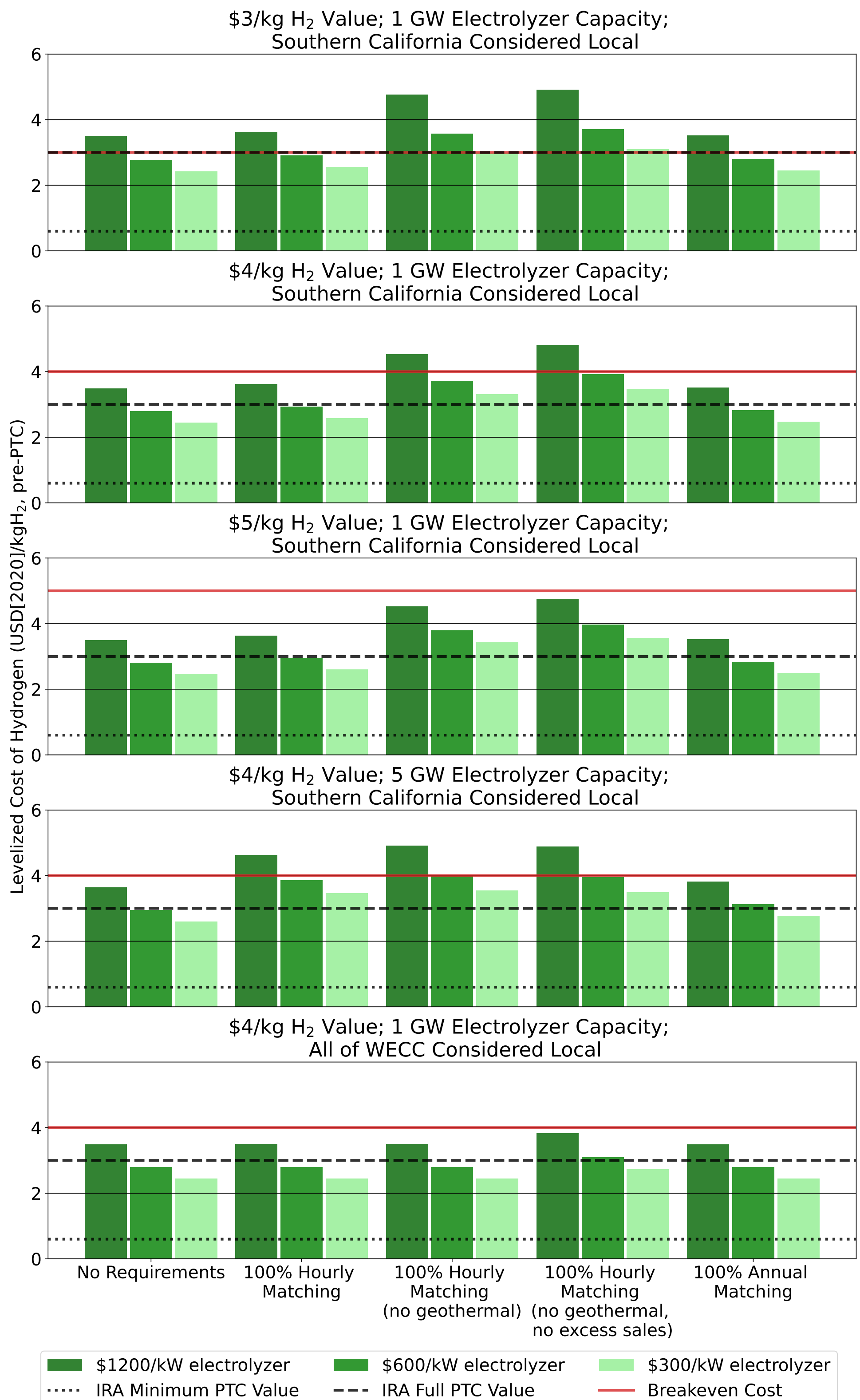

Figure 5. Levelized cost of hydrogen (LCOH) for production in southern California under the same scenarios shown in Figures 2 and 3, compared with potential revenues from sales. LCOH values are provided for a range of potential electrolyzer capital costs.

4. Discussion and Conclusion

In this study we have used capacity expansion modeling to demonstrate a system of clean energy procurement that could enable grid-based hydrogen production in the United States to qualify for the 45V PTC. By requiring hydrogen producers to match their grid electricity consumption with local, newly-built clean generation on an hourly basis, regulators can ensure that hydrogen is produced at effective emissions rates equivalent to those of behind-the-meter installations. Each component of the proposed requirement - locality, additionality, and hourly matching - is critical to ensuring that hydrogen produced via grid-based electrolysis is truly low carbon. Violation of any of these conditions can result in subsidized hydrogen production with an effective embodied emissions rate worse than unabated SMR. By enforcing all three, regulators can ensure that grid-based hydrogen production is reliably clean. Although electricity market conditions will differ across the country, the mechanics that enable 100% Hourly Matching requirements to effectively minimize hydrogen's embodied emissions (see Section 3.2) are likely to be consistent nationally. It should be noted that the present analysis assumes no major barriers to clean energy deployment outside of land availability. If transmission interconnection or permitting bottlenecks constrain clean energy deployment to less than the economic optimum (i.e. demand for clean energy exceeds supply), then any increase in electricity demand from electrolysis will necessarily increase grid emissions regardless of the clean energy matching requirement put in place.

We find that meeting a 100% Hourly Matching requirement will come at an additional cost to hydrogen producers compared to alternative options, but that the full PTC subsidy will likely be large enough to support investment even with the additional cost of compliance. 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 reduce the additional cost of an hourly matching requirement [21, 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 credit 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 electrloyzer consumption with new, locally-procured, carbon-free generation. While initial projects may opt to pursue purely behind-the-meter supply, the growing maturity of accounting standards, protocols, and market mechanisms for creation, tracking, and trading of time-based energy attribute certificates (T-EACs) will unlock additional opportunties to demonstrate near-zero embodied emissions from grid-connected electrloysis. 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.

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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. [24]. 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 [19].

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