Producing hydrogen from electricity:

How modeling additionality drives the emissions impact of time-matching requirements

An MIT Energy Initiative Working Paper

April 2023

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MIT Energy Initiative

MITEI-WP-2023-02

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Abstract

The United States' Inflation Reduction Act (IRA) includes a hydrogen (H_2) production tax credit (PTC) to subsidize low-carbon H_2 up to \$3/kg. It is hard to quantify the emissions impact of electrolyzers using grid electricity and contracting "additional" grid-interconnected renewable electricity; the H_2 producer offtakes its electricity supply from newly installed low-carbon generators that are not co-located with the electrolyzer. Recent research offers conflicting guidance on qualifying time-matching requirements, which we find can be explained by differences in the modeling of additionality requirements. One approach considers any resources that are not operating prior to the installation of the electrolyzer to be additional — i.e., H_2 and non-H_2 electricity demand "compete" for entering renewables. Another approach enforces a stricter definition of additionality by only considering low-carbon electricity supply that would otherwise not be deployed without H_2 production to be additional — we call this a "non-compete" framework. We model both approaches for case studies of the Texas and Florida grids and confirm that the additionality framework drives the consequential emissions impact of H_2 production. We estimate significantly less consequential emissions under an annual time matching requirement in the "non-compete" framework. Introducing an upper limit to the electrolyzer's capacity factor can reduce consequential emissions with annual time-matching under the "compete" framework. We argue that because the demand for electrolytic H_2 is still relatively small, today's context more closely resembles a "non-compete" framework and, thus, a low consequential emissions impact with annual time-matching is likely. However, as demand for electrolytic H_2 grows, the risk of a higher consequential emissions impact increases under annual time-matching, as the paradigm shifts to resemble the modeled "compete" framework. Hence, we argue for a "phased approach" in the requirements for the attribution of the PTC: annual matching in the near term with a re-evaluation leaning towards hourly matching later on in the decade.

1. Introduction

Hydrogen (H_2) is increasingly viewed as an important product for economy-wide decarbonization [1], [2], and policies are being promulagated to encourage its low-carbon production, such as production tax credits (PTC) as part of the U.S. Inflation Reduction Act (IRA). These policies to incentivize low-carbon H_2 must wrestle with how to qualify production as 'low-carbon,' which is particularly challenging for electrolysis-based H_2 production sourcing electricity from the grid. For instance, simply using existing grid-connected electricity to power water electrolyzers, even in high variable renewable energy (VRE) grids in the United States in 2021, such as California's, would lead to emissions from H_2 production that not only exceed the highest emissions tier in the PTC (4 $kgCO_2eq/kg\ H_2$), but are also greater than the per-unit emissions from natural gas reforming without carbon capture and storage (CCS) [3], [4]. A straightforward way to produce so-called "green" H_2 and meet PTC emissions thresholds would be to use electricity supplied exclusively from co-located low-carbon electricity generation (e.g., wind and solar). However, such "green" H_2 installations may be impractical to deploy in many instances, whether due to space constraints or production costs (e.g., as a result of low local wind speeds or solar irradiation) [5]. Instead, it may be appealing to produce H_2 from electricity by combining the two strategies: connect electrolyzers with the grid and use that connection to access new "additional" low-carbon electricity resources deployed elsewhere on the grid. Such an approach could enable lower electricity input costs for H_2 production and limit the emissions impact, while allowing H_2 to be produced where it is consumed rather than where VRE supply is abundant, thereby reducing H_2 transport costs. However, due to the temporal and spatial dynamics of grid operations, instantaneous power flows from a grid-connected generator cannot be associated with a particular grid-connected electricity load. This has led to interest in defining qualifying requirements for procured low-carbon electricity supply to ensure that H_2 produced is indeed "green" and meets the emissions intensity threshold set by policy (e.g., the H_2 PTC in the U.S. context).

Recent research papers by Ricks et al. [6] and Zeyen et al. [7] offer conflicting guidance on qualifying requirements. Both papers require 'additionality,' whereby the producer contracts for its electricity supply from new, low-carbon generators. However, they differ on whether this additionality requirement can be successfully enforced using an "annual time-matching" requirement or whether a stricter "hourly time-matching" requirement is necessary to assure that the incentivized H_2 production is truly low-carbon from a systemwide perspective. Zeyen et al. find that annual matching works well in certain contexts and implementations, whereas hourly matching raises the cost of H_2 production compared to annual matching in certain contexts. In contrast, Ricks et al. find that annual matching fails — the incentivized H_2 production results in significantly higher emissions — and hourly matching is needed. The conflicting results of the two papers are a puzzle, and they present a conundrum for policymakers tasked with making imminent decisions about how to implement H_2 PTC policies.

In this paper, we resolve this puzzle by identifying the underlying modeling choice driving the two results. Both papers start by constructing a (future) counterfactual 'baseline' power system (orange circle in Figure 1) absent H_2 production and the associated incentive policies, and then evaluate the emissions impact of H_2 production against the emissions in the baseline power system (so-called 'consequential' emissions, see section 2.3). Because of the favorable economics of VREs, the baseline power system contains more low-carbon generators compared to today's power system (white circle in Figure 1). What determines the emissions impact of the H_2 policy is whether it succeeds in incentivizing further additional low-carbon generation relative to the baseline. Zeyen et al. require the H_2 producers to contract with low-carbon generators not already in the baseline system (yellow circle in Figure 1B) [1], whereas Ricks et al. only require

[1] No expansion or retirement of assets unrelated to hydrogen production are allowed.

the H_2 producers to contract with low-carbon generators not already in today's power system (purple circle in Figure 1A).

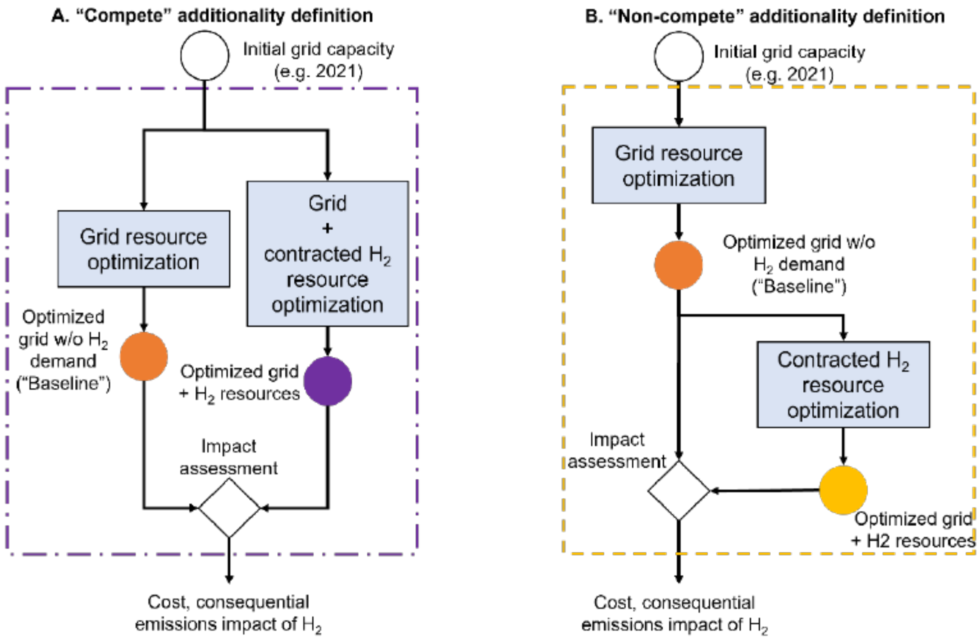

Figure 1. Approaches for evaluating the cost and consequential emissions impact of electrolytic H_2 production based on the two alternative definitions of additionality. The "Compete" definition (purple dotted box, part A), mirrors the approach of Ricks et al. [6] and allows for competition among investment in resources contracted for H_2 production and other grid resource investments. The "Non-compete" definition of additionality (yellow dotted box, part B) follows the approach of Zeyen et al. [7] where contracted H_2 resources are optimized after fixing investment in non-H_2 related grid resources. Here, contracted H_2 resources refer to battery storage, wind, solar generation, electrolyzer, and H_2 storage resources to meet H_2 demand and satisfy the specified time-matching requirement. Note that the baseline grid in both additionality frameworks is the same, while the optimized grid with H_2 resources is different (as indicated by the different colors of the circles).

In a nutshell, the major reason behind the different results presented in the two papers is that in the Ricks et al. modeling, low-carbon generation built in the baseline system (orange circle in Figure 1A) to serve the non-H_2 power demand can be "shifted" in the counterfactual H_2 policy power system (purple circle in Figure 1A) to serve the H_2 power demand. Also, under this modelling approach, it can happen that higher-carbon generation that is present in the initial grid (white circle in 1A) is retired in the baseline system but retained in the counterfactual H_2 policy power system to serve the non-H_2 power demand. Such dynamics, i.e., renewables being "shifted" from serving non-H_2 power demand to H_2 power demand and potentially less retirement of high-carbon generation in the counterfactual H2 policy power system versus the baseline scenario, play a much larger role under annual matching than under hourly matching. In Zeyen et al. this shifting is proscribed, so that the annual matching largely succeeds in driving the desired additionality vis-à-vis the benchmark system and thus does not lead to high levels of consequential emissions.

To resolve this difference, we used an open-source energy system model [8] to conduct a regional case study of the Florida (FRCC) and Texas (ERCOT) grids, where the initial power system is defined per 2021 conditions (white circles in Figure 1). We compare how annual and hourly time-matching requirements fair in terms of the consequential emissions and costs of H_2 production when subject to the two alternative definitions of additionality. We call these alternative definitions of additionality the "compete" and "non-compete" definitions, respectively, as summarized in Figure 1. We also evaluate a variant of the annual time-matching requirement proposal that also imposes a maximum annual capacity factor limit on the electrolyzer, which Zeyen et al. originally suggested as a possible means of reducing the emissions impact of annual time-matching but did not quantify. Finally, our regional case studies and focus on near-term technology cost assumptions allows us to understand the near-term impacts of H_2 production via electrolyzers in relatively low-VRE dominant power systems. For example, the contributions of grid-connected VRE generation in FRCC and ERCOT grids as of 2021 were 3.0% (3.0% solar, 0% wind) and 26.5% (3.1% solar, 23.4% wind), respectively, which is generally lower than the systems without H_2 demand evaluated in the Ricks et al. and Zeyen et al. papers. Low VRE penetration grids are a common occurrence in the U.S. as of 2021 - for example, Mid-Atlantic (2.4%), New England (6.1%), and East South Central (0.4%) [9].[2]

Across the two case studies, we confirm that the consequential emissions impact of H_2 production under annual time-matching requirements is heavily dependent on the underlying additionality modeling framework. In particular, under the "compete" framework, the consequential emissions associated with annual time-matching are much larger than the H_2 PTC emissions limits, while the "non-compete" framework results in near-zero consequential emissions for both case studies and evaluated demand and technology scenarios. The trends in the levelized cost of hydrogen (LCOH), after including applicable PTC based on modelled consequential emissions, also largely follow the trends in consequential emissions for annual time-matching, with values >$1/kg and <$1/kg in all cases of the "compete" and "non-compete" frameworks, respectively. For the hourly time-matching requirements, we find that the results are less sensitive to the additionality modeling framework but are more sensitive to the scale of H_2 demand and whether the electrolyzer can operate flexibility. Flexible electrolyzer operation is necessary, but not sufficient, to achieve LCOH (with PTC) below $1/kg under hourly time-matching requirements for both additionality modeling frameworks. The straightforward reason being that hourly matching comes with increased deployment of VRE capacity and H_2 storage capacity compared to the corresponding demand scenarios with annual time-matching requirements.

While modeling can readily quantify these two polar scenarios, in reality, the consequential impacts of H_2 production are much less clear and will depend on the pace of VRE deployment on the grid and growth in green H_2 demand. Today the demand for green H_2 is still relatively small and this will likely remain true into the near future. At the same time, VRE deployments are likely to grow substantially, judging from the relatively long interconnection queues across many regions in the U.S. and given the VRE-specific incentives in the IRA. In such a context, VRE resource deployments for grid decarbonization will be significantly larger than those contracted for H_2 production in the near-term, which resembles the modeled "non-compete" additionality framework, where annual time-matching results in near-zero consequential emissions in our analysis. Our findings suggest that enforcing an hourly time-matching requirement in the near-term, when the risk of high emissions from annual time-matching is low, creates additional cost and implementation barriers for scaling up electrolytic H_2 production. This would be counter-productive to the PTC objective of stimulating green H_2 demand in the economy. However, as demand for green H_2 grows, the risk of higher consequential emissions impact increases, and the paradigm shifts to be like the modeled "compete" framework, in which low consequential emissions only seem achievable under an hourly time-matching requirement.

The remainder of the paper is structured as follows. In Section 2, we elaborate upon the background for uninitiated readers and describe methods, with further details provided in the supporting information (SI). In Section 3, we present the results. In Section 4, we provide a discussion. We end with a conclusion.

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[2] The regions are defined as follows (as per EIA reference): Mid Atlantic: New Jersey, New York, Pennsylvania. New England: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont. East South Central: Alabama, Kentucky, Mississippi, Tennessee.

2. Methods

In this section we first provide a brief discussion of the model we employ, which is followed by a description of the context and the key assumptions in our analysis and how these are similar or different to those of Ricks et al. [6] and Zeyen et al. [7]. Finally, we discuss the key metrics that are computed and discussed in the results section.

2.1 Model overview

This study uses the Decision Optimization of Low-carbon Power and Hydrogen Networks (DOLPHYN) model [8], an open-source energy systems capacity expansion model that co-optimizes investment and operation of electrical power and H_2 sectors while considering their spatially and temporally resolved interactions. The model minimizes the total system cost associated with bulk infrastructure of both commodities (electricity and H_2). This includes 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. The cost minimization is carried out subject to many system and technology-level constraints, including a) ramping limits and temporally dependent resource availability limits for VRE generation, and b) system-level constraints, including hourly energy supply-demand balance for H_2 and electricity at each location, as well as case-specific annual CO_2 emissions limits or hourly/annual energy share requirements. Further details of the model formulation and setup can be found in [8].

2.2 Context and key assumptions: similarities and differences between this work, Ricks et al., and Zeyen et al.

Table 1 provides a high-level overview of the key assumptions and contexts in this study and two other recent papers that examine the implementation of the H_2 PTC. In the introduction (Figure 1) we have explained the two relevant additionality modeling frameworks. In contrast to the two relevant papers, we assume no grid congestion between the node where electricity is consumed by the electrolyzer and the node(s) where the purchased electricity is injected – thus, we are implicitly ignoring the impact of spatial-matching requirements. In what follows, we cover the context and other key assumptions in more detail.

Table 1. Comparison of key assumptions and context between this study and two other recent papers with the significant overlap on the research questions of interest.

	Ricks et al. **[6]**	Zeyen et al. **[7]**	This work
Additionality definition evaluated?	"Compete"	"Non-compete"	"Compete" and "Non-compete'
Inter-regional transmission constraints?	Yes	Yes	No
Region and time horizon of interest	Western U.S. — 2030	Germany, Netherlands — 2025/2030	Florida (FRCC), Texas (ERCOT) —2021
Exogeneous H_2 demand characterization	No demand enforced, both in quantity and profile	Constant hourly H_2 demand	Constant hourly H_2 demand
Energy storage options evaluated	Li-ion	Li-ion, tank-based gaseous H_2 storage and	Li-ion, tank-based gaseous H_2 storage

		other lower cost forms of H_2 storage	
Time-matching requirements analyzed	• Annual matching • Hourly matching without excess sales • Hourly matching with excess sales • Weekly matching	• Annual matching • Hourly matching without excess sales • Hourly matching with 20% excess sales	• Annual matching • Annual matching with max capacity factor limit • Hourly matching with excess sales

2.2.1 Region and time horizon of interest

Ricks et al. evaluate the impact of alternative time-matching and spatial matching requirements in the context of the Western United States grid for 2030. In contrast, Zeyen et al. study the impact of emissions and cost impact of alternative time-matching requirements for a European case study. Our analysis is based on two case studies that are representatives of low and high end of VRE generation share in the U.S. as of 2021: the Florida Reliability Coordinating Council (FRCC) and Electric Reliability Council of Texas (ERCOT). FRCC 2021 includes a very low annual generation share of renewables (3.0 from solar PV), whereas ERCOT 2021 includes a higher VRE generation share but based mostly on wind—with onshore wind making up 23.4% of generation and PV making up only 3.1%. The data inputs and sources used to define the 2021 system for both case studies are provided in the SI. Relevant technology cost and performance assumptions are reported in Table S1 and Table S2, and fuel costs are reported in Table S3. Power generation capacity for all resources for FRCC and ERCOT are reported in Table S4. Annual demand and generation information is reported in Table S5. Hourly VRE capacity factors and hourly demand profiles for FRCC and ERCOT are visualized in Figure S1 and Figure S2, with VRE profiles generated by averaging data from subregion of ERCOT and FRCC, as visualized in Figure S3.

2.2.2 Exogeneous H_2 demand characterization, energy storage options and electrolyzer operating modes

Ricks et al. do not enforce an exogeneous H_2 demand, either in quantity or in profile. As in Zeyen et al., in our analysis we assume a constant hourly H_2 demand. A constant H_2 demand is what would be expected from typical industrial applications that are met by electrolysis-based H_2 production [10]. Thus, irrespective of the electrolyzer operating mode, the combination of electrolyzer output plus net discharge of H_2 storage, where available, must meet a constant H_2 load for each hour of the year.

Regarding storage technologies, Ricks et al. only include lithium-ion batteries. Inherently, as the H_2 demand is not fixed exogenously, the electrolyzer can operate flexibly in their paper. In contrast, while Zeyen et al. and our analysis assume a constant exogeneous H_2 demand, this does not imply that the electrolyzer can only be operated in baseline mode. Instead, flexible electrolyzer operation is considered with the aid of investments into H_2 storage options.

More precisely, in our model, under *baseload operation*, the available electrolyzer capacity, after accounting for planned outages[3], is fixed to be equal to the exogeneous H_2 demand and operates at 100% utilization for all hours of the year. Electricity demand from the electrolyzer is constant for all hours. Such a mode of operation may be appealing to maximize capital utilization and minimize degradation.[4] In contrast, under *flexible operation*, exogenous, time-invariant H_2 demand must be met, as in the baseload case, but electrolyzer size and operation, along with the size of H_2 storage, are decision variables (see Eq.

[3] The electrolyzer capacity installed is set such that at any hour only 95% of the installed capacity is available for generation. This is to account for planned outages related to maintenance.
[4] Such operation is also incentivized by having a PTC in place rather than a non-distortive ITC. However, this discussion goes beyond the scope of this paper.

S1 in SI). Flexible electrolyzer operation can lead to the electrolyzer being oversized relative to exogenous hourly H_2 demand, since it is opportune to produce additional H_2 during times of high VRE availability. That H_2 can be stored and discharged at other times when the electrolyzer is not operating (presumably because of low VRE availability), in order to meet the specified PTC tier emissions threshold. Because the total amount of H_2 produced is fixed, the available PTC does not impact the operational behavior of the electrolyzer and therefore we do not consider it in the model, but rather include it when estimating the levelized cost of H_2 (see Section 2.5 and Results).

We evaluated the system outcomes for varying levels of hourly H_2 demand of 18.4 to 92.1 tonnes of H_2 per hour (0.16 to 0.81 MT/year), that for typical electrolyzer specific power consumption (54.3 MWh/tonne), ranges from 1 to 5 GW of hourly electric power consumption. For simplicity, when discussing results, we use labels of like "1 GW" to indicate an hourly H_2 demand level of 18.4 tonnes of H_2 per hour.

2.2.3 Time-matching requirements

Like in Ricks et al. and Zeyen et al., we model two time-matching requirements – hourly and annual. However, here we compare the results for these time-matching requirements under two alternative frameworks for additionality, as defined earlier.

Annual time matching is implemented via a constraint that requires that the annual generation output from contracted wind and solar resources must equal the annual electricity consumption of the electrolyzer (see Eq. S2 in SI). In contrast, the *hourly time matching* requirement is modeled by implementing a constraint that requires the net hourly output of contracted resources (VRE generation and battery storage net discharge[5]) to be at least equal to the hourly electricity consumption of the electrolyzer (see Eq. S3 in SI). To ensure battery storage charges from eligible VRE generation resources, we only allow the contracted battery, if deployed, to charge in each hour up to the available generation from contracted VRE resources (see Eq. S4 in SI). In this implementation, the hourly time matching requirement allows for the contracted resources to sell any excess electricity in a given hour (e.g., an hour with high solar or wind availability) to the grid and earn revenues that can partly offset the capital cost associated with the contracted resources and thereby reduce the cost of H_2 production. The option to sell electricity to the grid when economical is also available in the annual time-matching requirement case, so long as the sum of annual generation matches that of the electricity consumption of the electrolyzer.

We also model a variant of the annual time-matching requirement that also includes a maximum annual capacity utilization requirement for the flexibly used electrolyzer, which effectively translates into a minimum capacity deployment constraint for an exogeneous annual H_2 demand to be met (see Eq. S5 in SI). This constraint has been suggested as a way to minimize the consequential emissions impact of electrolytic H_2 production, with the hypothesis that a producer needing to meet a fixed H_2 demand will be incentivized to forgo production during periods of high electricity prices, which (often) correlate with periods of high marginal grid emissions intensity in a fossil-fuel dominant power system (i.e., in most systems it means coal-fired power generation is the marginal generation technology).

2.3 Metrics of interest

The emissions impact of H_2 production is evaluated using the *consequential emissions intensity*, defined as *the difference in power system emissions with and without* H_2 *demand divided by the annual quantity of H_2*

[5] For hourly time-matching, we allow for VRE and battery storage expansion, since in some cases it may be infeasible to meet the hourly time matching requirement without energy storage, e.g., when relying on solar generation alone. For annual time-matching, however, battery storage is not essential and hence was not considered, although battery deployment could lower system costs and levelized cost of hydrogen in some cases.

produced. As noted by others [6],[7], this is an appropriate metric for assessing emissions intensity in modeling exercises; however, alternative metrics are needed for real world accounting, since the counterfactual "base case" used to calculate consequential emissions cannot be observed. Although the PTC focuses on lifecycle GHG emissions, as a simplification, our analysis only considers CO_2 emissions related to fossil fuel combustion for electricity generation since these will dominate overall emissions.[6]

Aside from consequential emissions intensity, we evaluate *the levelized cost of hydrogen (LCOH),* which approximates the cost to the H_2 producer who invests in the electrolyzer and H_2 storage, as well as the additional low-carbon electricity generation that is required for the H_2 to be eligible for the PTC under alternative time-matching and additionality requirements. The LCOH can also be thought of as a proxy for the minimum H_2 selling price that would lead to a zero profit for the H_2 producer over the lifetime of the investment in the electrolyzer. The LCOH includes: a) the capital cost of added VRE and battery storage (after the 30% investment tax reduction (ITC) under the IRA[7]), b) the cost of electricity purchases from the grid for H_2 production, c) revenue from electricity sales to the grid from the procured renewables (accounting for battery charging/discharging), and d) electrolyzer and H_2 storage fixed costs. Revenues and costs for electricity purchases and sales to the grid are accounted for based on the shadow price of electricity supply-demand balance constraint enforced for each hour of the year in the model.[8] In each case, we report the LCOH with and without including the applicable H_2 PTC.

3. Results

The results section is split into four parts. The first three sections provide a detailed discussion of the FRCC 2021 case study. First, we discuss how the resource mix is impacted under different scenarios. Second, we report the consequential emissions. Third, we discuss the impact of additionality modeling frameworks on the LCOH. In the fourth section, we provide a brief discussion of the ERCOT 2021 case study for the same metrics, with further details available in the SI.

3.1 Power sector resource impacts for FRCC 2021

Figure 2 shows the change in power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality frameworks.

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[6] While emissions from other lifecycle stages will impact the absolute lifecycle GHG emissions of H_2 production, the impact of matching requirements will primarily affect electricity consumption–related emissions as compared to emissions from other stages (e.g., electrolyzer manufacturing).

[7] The IRA allows for an eligible VRE and storage facility to either receive the credit as a ITC or PTC—as a simplification we restricted our analysis to the case when the VRE and battery storage owner only relies on the ITC, which may be the economical choice when capital costs of these assets are still high and/or resource quality is average to low [11].

[8] In practice, the H_2 producer may not directly invest in the VRE plus battery storage assets but could choose to sign a power purchase agreement (PPA) that pays another developer who has invested in these assets. Here, we are trying to approximate the cost of the PPA by accounting for the difference between the cost of electricity grid consumption incurred by the hydrogen producer and the revenues from sales of electricity from the VRE plus battery storage assets.

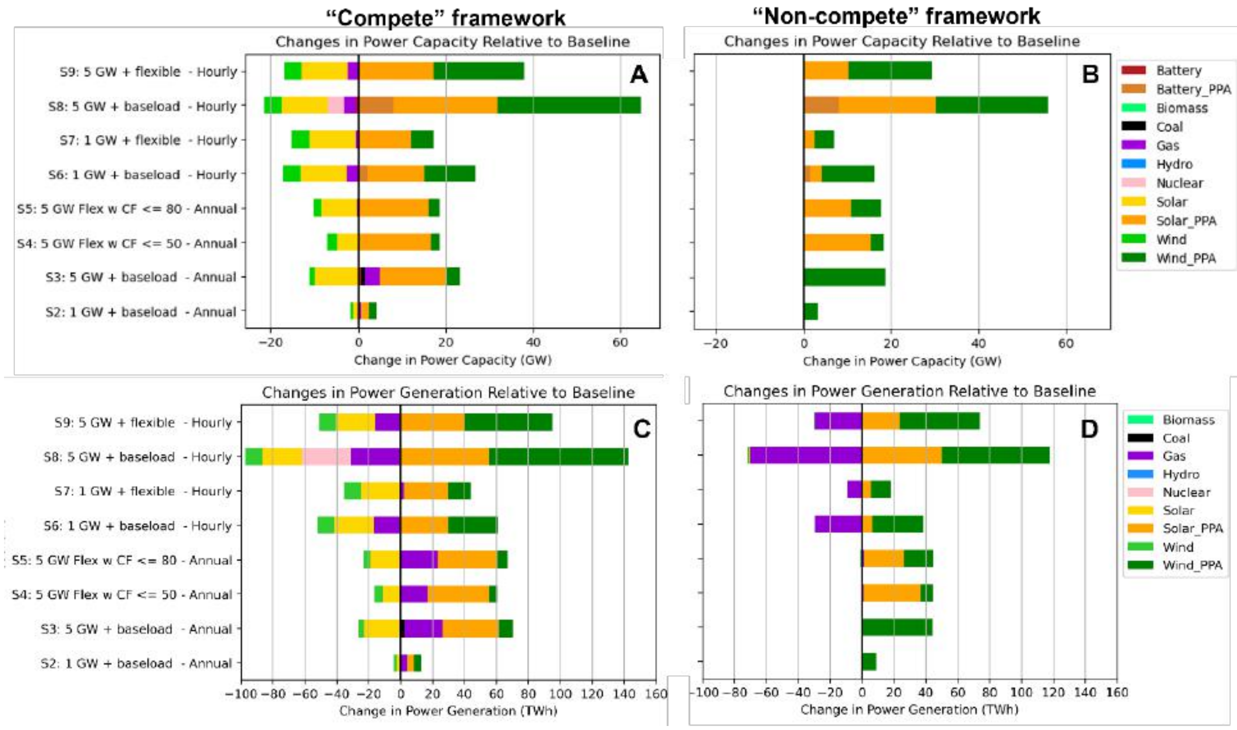

Figure 2. Change in power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality frameworks. Results correspond to the FRCC 2021 case study and are reported relative to the baseline scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1. 'CF' stands for the capacity factor of the electrolyzer. Resources with suffix "_PPA" refer to resources added specifically to meet time-matching requirements for H_2 production.

The main takeaway from Figure 2 is that the contracted power sector resources for H_2 production under annual time-matching requirements are more sensitive to the additionality definition than resources contracted under hourly time-matching requirements. In particular, wind generation is preferred to meet annual time-matching requirements under the "non-compete" framework, while solar generation plays a greater role in the "Compete" framework. Since the baseline grid expansion predominantly results in solar additions, increasing the solar generation share from an empirical baseline of 3% in 2021 to 19% in the model (see Figure S4), there is diminished economic value of further solar additions to meet the annual time-matching requirements under the "non-compete" framework. In contrast, under the "Compete" framework, where initial solar generation share is still at 2021 levels (3%), contracting solar PV for meeting annual time-matching requirements is cost-effective and outcompetes deployment of non-contracted solar PV resources that would have been deployed without H_2 demand – for example, see results for 5 GW + baseload - Annual scenario in Figure 2 A/C. At the same time, due to the diurnal availability of solar resources, there is a need for additional gas generation to meet incremental electricity demand for H_2 production during times of low solar availability (see Figure 3A). Any increases in gas generation under annual time-matching requirements are largely avoided in the "non-compete" framework since wind resources have availability spread out throughout the day. These resources are able to offset sufficient natural gas generation at times of high wind output to more than compensate for increased emissions at times of low wind output (see Figure 3B). Thus, although the dispatch of fossil-based generators is also altered in the "non-compete" framework, large changes in consequential emissions are not observed as the total volume of fossil-based generation remains more or less similar.

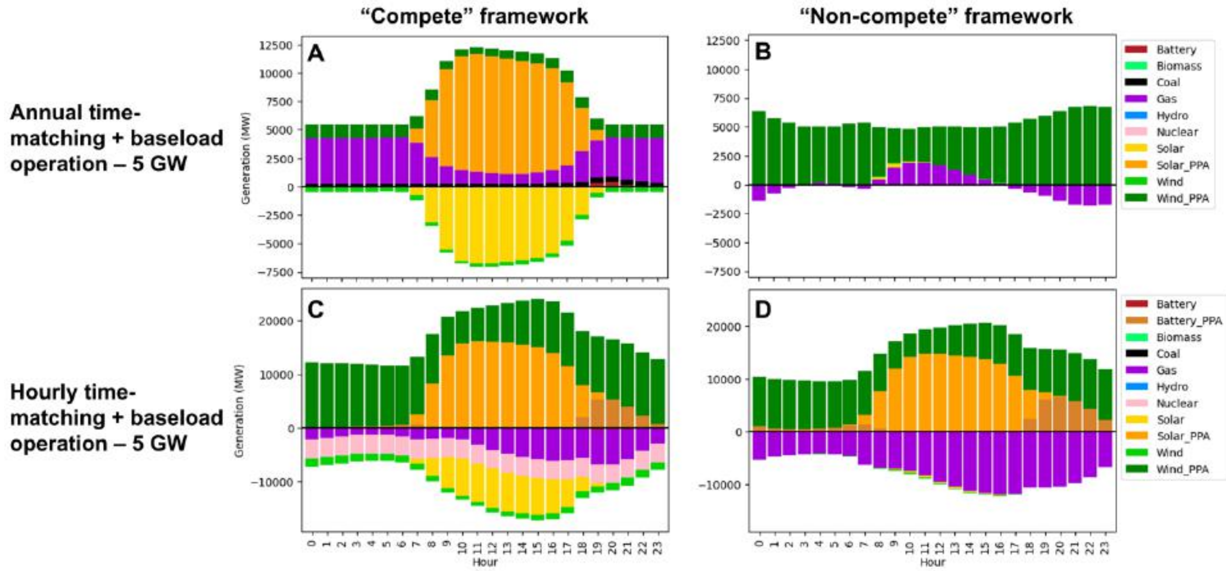

Figure 3. Difference in average hourly dispatch in FRCC 2021 between H_2 policy power system and baseline under the "Compete" (1st column) and "Non-compete" definitions (2nd column) of additionality and annual (top row) and hourly time-matching requirements (bottom row): ***A and B****: 5 GW of H_2 production with baseload electrolyzer operation and annual time-matching requirements.* ***C and D****: 5 GW of H_2 production with baseload electrolyzer operation and hourly time-matching requirements. Resources with suffix "_PPA" refer to resources added specifically to meet time-matching requirements for H_2 production.*

As opposed to annual time-matching requirements, Figure 2 highlights that hourly time-matching requirements leads to larger capacity of contracted resources as well as reductions in annual natural gas generation compared to the baseline grid scenario (see Figure 2 D). The increased capacity deployment is necessary to compensate for the intermittency of VRE generation while simultaneously ensuring that generation plus net-discharge of storage from contracted resources is at least equal to hourly electrolyzer power consumption (see Eqn. S3). The increased capacity deployment also implies that these contracted resources will generate in excess of electrolyzer power demand at certain times that can be dispatched to meet non-H_2 electricity demand and displace more expensive generation on the margin (Figure 3C/D). The displaced generation includes VRE resources that would have been deployed in the baseline grid as well as natural gas generation. As discussed later, the excess electricity sales could cross-subsidize the cost of H_2 production under hourly time-matching requirements. Moreover, not allowing excess electricity sales from contracted power sector resources to the grid would lead to the trivial, but more expensive solution of an islanded H_2 production system, involving co-located VRE and energy storage resources [6], [7].

The ability to operate the electrolyzer in a flexible manner allows for shaping electricity consumption for H_2 production to better match the availability of contracted VRE resources, while relying on relatively low-cost H_2 storage (modeled based on cost of above-ground tank storage, see Table S2) to meet H_2 demand. Consequently, flexible electrolyzer operation results in lower capacity deployment for both annual and hourly time-matching requirements under both additionality definitions, as shown in Figure 2. Notably, flexible electrolyzer operation avoids the need for expensive battery storage deployment to meet hourly time-matching requirements, in lieu of deploying H_2 storage capacity equal to 5-8 hours of H_2 demand for the annual time-matching requirement and 19-34 hours of H_2 demand for the hourly time-matching requirement scenarios (Figure S7-Figure S8). In the hourly time-matching requirement case, the corresponding electrolyzer capacity factor values range from 77% to 86%. In the case of annual time-matching requirements and the "compete" framework for additionality, flexible electrolyzer operation also results in smaller increase of natural gas generation compared to the baseload operation scenario (Figure

S6). For example, the increase in natural gas generation under the 5 GW + flexible operation with a 50% capacity factor limit is roughly half that of the corresponding case with baseload operation.

3.2 Consequential emissions impact for FRCC 2021

Figure 4 shows the consequential emissions intensity of H_2 production for alternative exogeneous H_2 demand levels, electrolyzer operation modes and time-matching requirements under the “compete” and “non-compete" modeling frameworks for additionality.

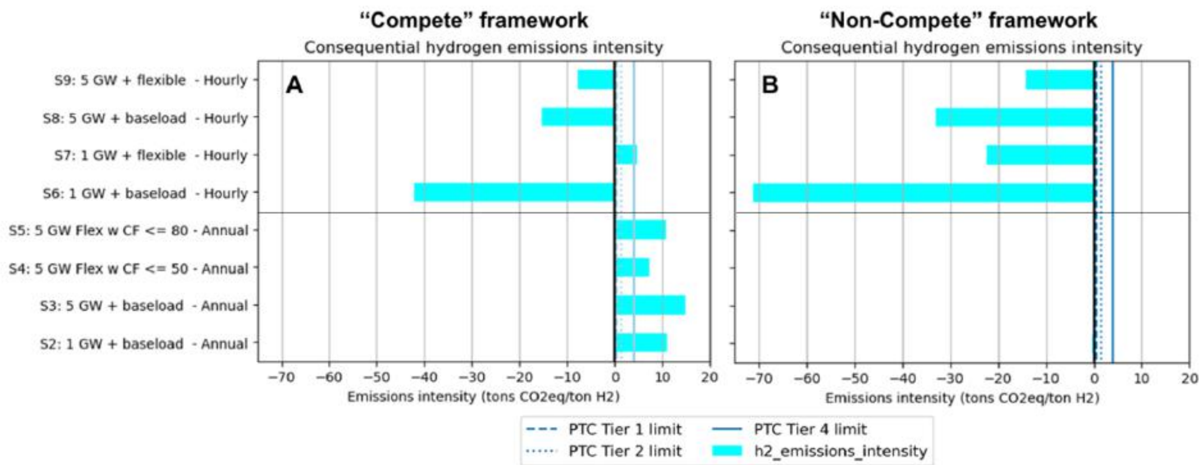

Figure 4: Consequential emissions intensity of H_2 production for alternative exogeneous H_2 demand levels, electrolyzer operation modes, and time-matching requirement under the “Compete” and “Non-compete" frameworks of additionality described earlier and highlighted in Figure 1. Results correspond to the FRCC 2021 case study and are reported to relative to the baseline scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1. Also shown are threshold emissions intensity values for H_2 PTC in the IRA, with the production meeting the Tier 1 limit eligible for up to \$3/kg PTC while those meeting Tier 2 and Tier 4 limits are eligible for PTC in the amount of \$1.0/kg and \$0.6/kg, respectively.

Figure 4 shows that the GHG emissions implications of electrolytic H_2 production mirror the changes in generation mix seen in Figure 2, with annual time-matching requirements generally leading to either near-zero emissions in the “non-compete” framework (because the total volume of natural gas generation vs. the baseline grid remains virtually unchanged) or highly positive in the “Compete” framework. In the latter case, the consequential emissions of the H_2 production under baseload operation are higher than the emissions intensity of H_2 production from natural gas without CCS [2]. Although flexible operation mitigates this effect by limiting natural gas generation vs. baseline grid with annual time-matching requirements under the “Compete” framework, the levels of flexibility investigated are insufficient to make the produced H_2 eligible for even the highest PTC threshold of 4 $kgCO_{2eq}/kg\ H_2$.

In the case of hourly time-matching requirements, consequential emissions are generally substantially negative under both additionality modeling frameworks. However, in the “compete” framework, we can still see the effect of competition with non-contracted grid resources resulting in less negative consequential emissions. Flexible operation reduces the capacity deployment of contracted power sector resources (Figure 2), which reduces the volume of excess electricity sales and consequently results in less negative consequential emissions compared to the corresponding baseload operation scenario, as shown in Figure 3. Interestingly, in the 1 GW H_2 demand scenario under the “Compete” framework, the combined effect of flexible operation and competition with other grid resources results in a positive consequential emissions impact with hourly time-matching requirements. Here, there is greater reliance on solar to meet hourly time-matching requirements compared to the corresponding baseload operation scenario. At the same time, the lack of any contracted battery storage implies a greater reliance on natural gas to meet peak net load requirements (Figure S5) that ultimately results in positive consequential emissions. Higher levels of H_2 demand shift the preference for contracted VRE capacity towards wind rather than solar PV, even in the flexible operation case, and thus result in negative consequential emissions intensity.

3.3 Levelized cost of hydrogen (LCOH) for FRCC 2021

Figure 5 shows the LCOH for alternative exogeneous H_2 demand levels, electrolyzer operation modes, and time-matching requirements under the “compete” and “non-compete" modeling frameworks for additionality.

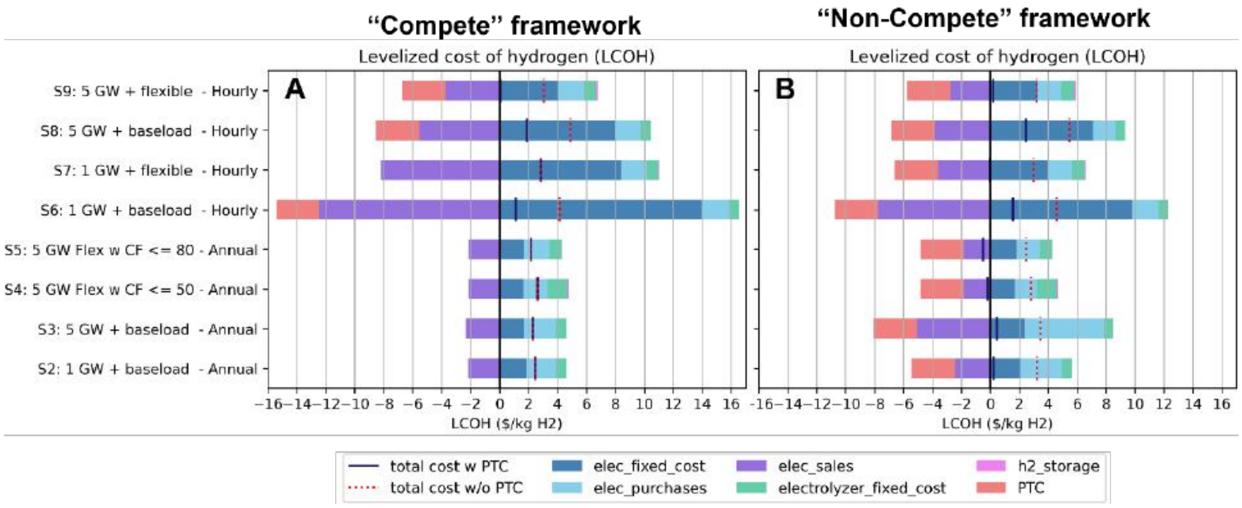

Figure 5: Levelized cost of H_2 for the FRCC 2021 case study under scenario with different H_2 demand (1, 5 GW equivalent power consumption), time-matching requirements (annual vs. hourly), additionality frameworks (“Compete” vs “Non-compete”) and electrolyzer operation modes (Baseload vs. flexible). Levelized cost calculated per description provided in Section 2.5. elec_sales = revenues earned from selling excess electricity to the grid using contracted power sector resources ; elec_purchases = cost of grid electricity purchased to operate the electrolyzer; electrolyzer_fixed_cost = annualized capital and fixed operating and maintenance (FOM) cost of the electrolyzer; elec_fixed_cost = annualized capital and FOM cost of contracted power sector resources, after accounting for investment tax credit (30%); h_2_storage= capital and FOM cost of gaseous H_2 storage system, which includes the capital cost of the compressor and tank. The total cost with PTC (total cost w PTC) shows the LCOH after accounting for PTC based on consequential emissions for each case.

A key observation from Figure 5, which is consistent with the existing literature, is that in nearly all cases, when disregarding the attribution of a PTC, the LCOH is higher under hourly versus annual time-matching requirements. This finding relates to Figure 2, which shows that significantly more resources need to be built to meet hourly versus annual time-matching requirements. This finding is true irrespective of the additionality modeling framework. Under the hourly time-matching requirement and baseline electrolyzer operation mode, the LCOH after including the PTC is still greater than $1/kg and thus not competitive. In the other cases, especially under annual time-matching, electrolytic H_2 production can be competitive if a 3$/kg PTC is awarded.

Another general finding is that flexible electrolyzer operation generally reduces the LCOH compared to the corresponding baseload operation scenario. The reduction in contracted power sector resources more than offsets any increases in the fixed cost of electrolyzer and H_2 storage.[9] This finding holds irrespective of the additionality modeling framework or time-matching requirement. This result is consistent with other studies

[9] The case of 1 GW with flexible electrolyzer operation and hourly time-matching requirement under “compete” framework is an exception that needs further clarification. Here, although the LCOH without accounting for the PTC is lower for the flexible case vs. the baseload operation because the flexible case is ineligible for the PTC (see section 3.2 for further discussion), the LCOH with PTC is higher for the flexible operation case.

modeling electricity-H_2 sector interactions that note the importance of electrolyzer flexibility to minimize the cost of H_2 production and support grid decarbonization efforts [12]. Further, while our analysis models above-ground H_2 storage that in principle does not have location constraints, the availability of even lower cost H_2 storage options like geological H_2 storage or lower electrolyzer capital costs will make flexible operation even more compelling from an LCOH perspective.

Figure 5 shows that the LCOH without PTC attribution is generally greater in the "non-compete" framework as compared to the "compete" framework in all scenarios. Part of the driver of this result is the lower value of excess electricity sales to the grid under the "non-compete" framework versus the "compete" framework, since electricity prices are depressed in the former case due to greater amounts of initial VRE generation. Consequently, higher fractions of electricity fixed costs are allocated to the LCOH in the "non-compete" framework – for example, in the 1 GW + baseload electrolyzer operation scenario, the net electricity cost allocated to cost of H_2, defined as electicity_fixed_cost – elec_sales in Figure 5, is $2.08/kg in the "non-compete" framework vs. $1.52/kg in the "compete" framework. This finding is further corroborated by the declining value of revenue earned from electricity sales ("elec_sales" in Figure 5) as H_2 demand increases from 1 to 5 GW under the hourly time-matching requirements in both the "compete" framework (12.4$/kg to $5.6/kg) and "non-compete" frameworks ($7.7/kg to 3.8$/kg).

3.4. Summary of system impacts for ERCOT 2021

Since many of the results for the ERCOT case study largely follow the trends seen in the FRCC case study, we only provide a brief summary of the key findings here with additional results provided in section S4. As was observed in FRCC, the power capacity and generation mix relative to the baseline case without H_2 demand in the ERCOT case study is sensitive to the adopted framework of additionality (see Figure S9). Under the "compete" framework, the construction of resources contracted to fulfil the H_2 demand displace some solar expansion from the optimized grid mix, which is generally not observed under the "non-compete" framework. Also similar to FRCC, the mix of resources contracted to meet the H_2 demand (i.e., 'PPA resources') is sensitive to the additionality framework, especially in the annual time-matching cases. Wind is favored in the "non-compete" framework since it is not competing with (i.e., partially displacing) solar additions as is observed in the "compete" framework. Finally, relative to the baseline, there is less retirement of coal in the "non-compete" hourly scenarios (see Figure S9).

Consequential emissions under the ERCOT 2021 cases strongly mirror the FRCC 2021 cases as shown in Figure 6. Under an annual time-matching requirement, the "non-compete" additionality framework results in slightly negative consequential emissions, whereas the "compete" framework finds positive consequential emissions exceeding the PTC's least stringent threshold. Like with FRCC, flexible electrolyzer operation reduces the consequential emissions associated with annual time matching in the "compete" framework (see the explanation in Section 3.2). Under the 50% capacity factor limit, the emissions can even be reduced to the extent that it is no longer worse than SMR (~10kgCO_2eq/kg H_2) [13], but not enough to meet PTC thresholds. An hourly time-matching requirement leads to zero or negative consequential emissions in all cases, except again for the case with 1 GW of H_2 demand with flexible operation in the "compete" framework, which is exactly as we observed in FRCC. Allowing for flexible operation under an hourly time-matching requirement reduces the level of negative emissions, since less renewable capacity is built/contracted to meet H_2 demand, meaning that there is less excess renewables generation from those resources to displace fossil fuel generation. Across the two additionality frameworks, flexible operation with hourly time-matching requirements is accompanied with H_2 storage capacity that can supply 25-37 hours of H_2 demand and electrolyzer capacity factors in the range of 82-86% (Figure S14-S15). The magnitude of difference between consequential emissions associated with hourly and hourly + flexibility is greater in ERCOT than FRCC, especially under the "non-compete" framework. This is likely because ERCOT favors wind relative to FRCC, and wind contracted for meeting H_2 demand has a greater effect on reducing overall system emissions due to its generation profile.

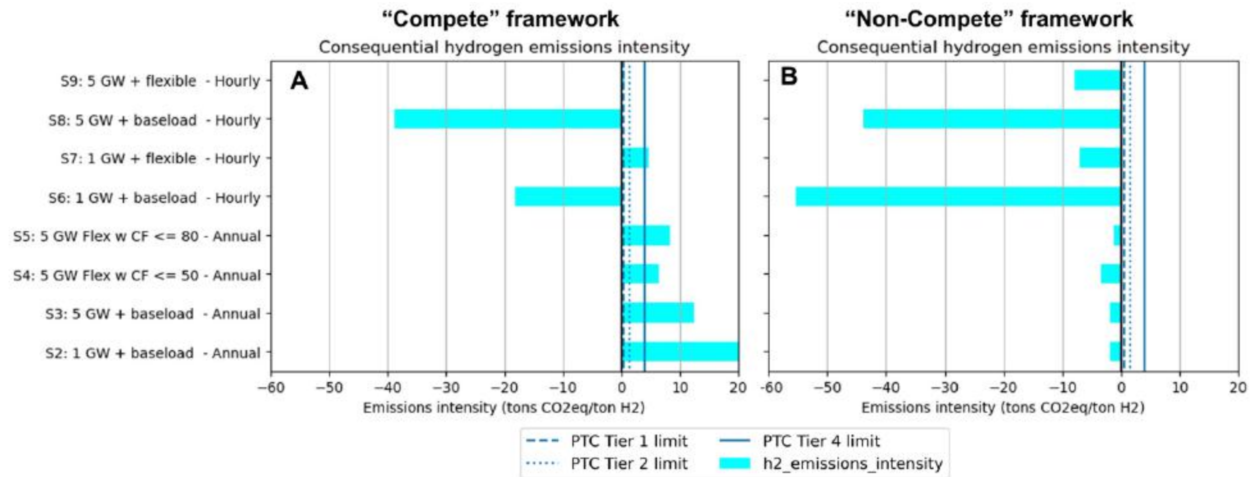

Figure 6: Consequential emissions intensity of H_2 production for alternative exogeneous H_2 demand levels, electrolyzer operation modes and time-matching requirements, under "Compete" and "Non-compete" definitions of additionality described earlier and highlighted in Figure 1. Results correspond to ERCOT 2021 case study and are reported relative to the baseline scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1. Also shown are threshold emissions intensity values for H_2 PTC in the IRA, with the production meeting the Tier 1 limit eligible for up to \$3/kg PTC while those meeting Tier 2 and Tier 4 limits are eligible for PTC in the amount of \$1.0/kg and \$0.6/kg, respectively.

Figure 7 shows the results for the LCOH are highly sensitive to the choice of additionality framework. Not considering the PTC, hourly time matching with baseload operation increases LCOH considerably relative to other scenarios across both additionality frameworks. Similar to the FRCC case study, revenues from excess electricity sales are significantly lower in the "non-compete" framework with hourly time-matching requirements, which illustrates how renewable resources contracted for H_2 under the "compete" framework may be competing with/displacing renewables for general grid expansion.

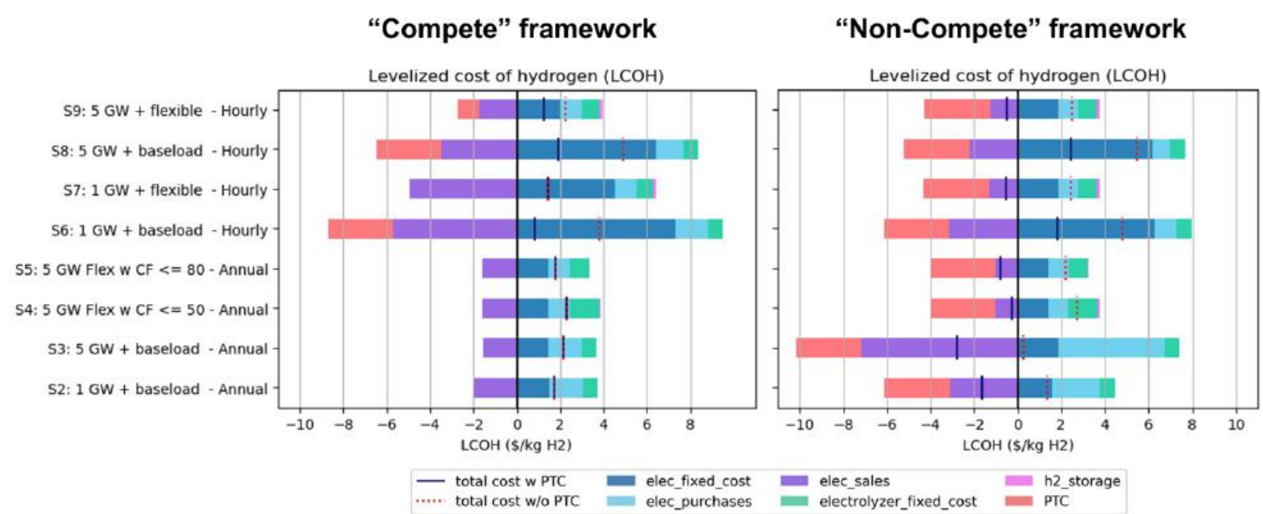

Figure 7: Levelized cost of hydrogen for the ERCOT 2021 case study under scenarios with different H_2 demand (1, 5 GW equivalent power consumption), time-matching requirements (annual vs. hourly), additionality definition ("Compete" vs "Non-compete"), and electrolyzer operation modes (Baseload vs. flexible). See the description of Figure 5 for details. The total cost with PTC shows the LCOH after accounting for PTC based on consequential emissions for each case.

4. Discussion

Two key results summarize our findings. The first result is that the consequential emissions from producing electrolytic H_2 is conditional upon how the additionality requirement is modeled. The second result has to do with differences in the LCOH between annual and hourly time-matching requirements, independent of the additionally modeling framework.

First, under the "compete" framework, in which we co-optimize the grid with the resources needed to fulfill H_2 demand, hourly time-matching requirements are the only possible way to reach consequential emissions that are under the threshold needed to receive any PTC (and this is not even guaranteed in all hourly time-matching cases). In contrast, under the "non-compete" framework, in which we first optimize the grid and sequentially optimize the resources needed to satisfy the H_2 demand, an annual matching requirement is sufficient in all cases to meet the threshold needed to receive the highest 3$/kg PTC.

Second, under any additionality modeling framework, hourly matching requirements generally lead to a higher LCOH relative to annual matching requirements (excluding the attribution of a PTC). Significantly higher capacities of renewables need to be installed under the hourly matching requirements and thus more capital and land is required. Flexible operation of the electrolyzer, whether it is under hourly or annual matching requirements, reduces the LCOH. Under the annual matching requirement, flexible operation also leads to lower consequential emissions versus baseload operation, while the opposite is true under hourly matching. In case an electrolyzer is forced to be flexible it will forego electricity consumption during hours when spot electricity prices are highest. Those hours are often also the hours with high marginal (and average) emissions since high prices often imply that coal or gas generation is the marginal technology. Overall, in case the policymaker would decide to exclusively grant a 3 $/kg PTC under an hourly matching requirement, the LCOH (including the PTC) could reach $-0.15 to $2.47 for FRCC and -$1.91 to $2.45 for ERCOT across the cases evaluated here. Instead, if the policymaker would decide to also grant a 3$/kg PTC under an annual matching requirement, the LCOH (including the PTC) could reach $-0.82 to $0.45 for the FRCC and $-2.76 to $-0.27 for ERCOT.

We summarize both key findings in Figure 8 below, where we show LCOH results for FRCC and ERCOT, considering a $3/kg PTC, and note where the PTC would be correctly or incorrectly provided, considering the modelled consequential emissions. Generally, the LCOH is lower in ERCOT compared to FRCC for every run due to greater resource availability (especially wind).

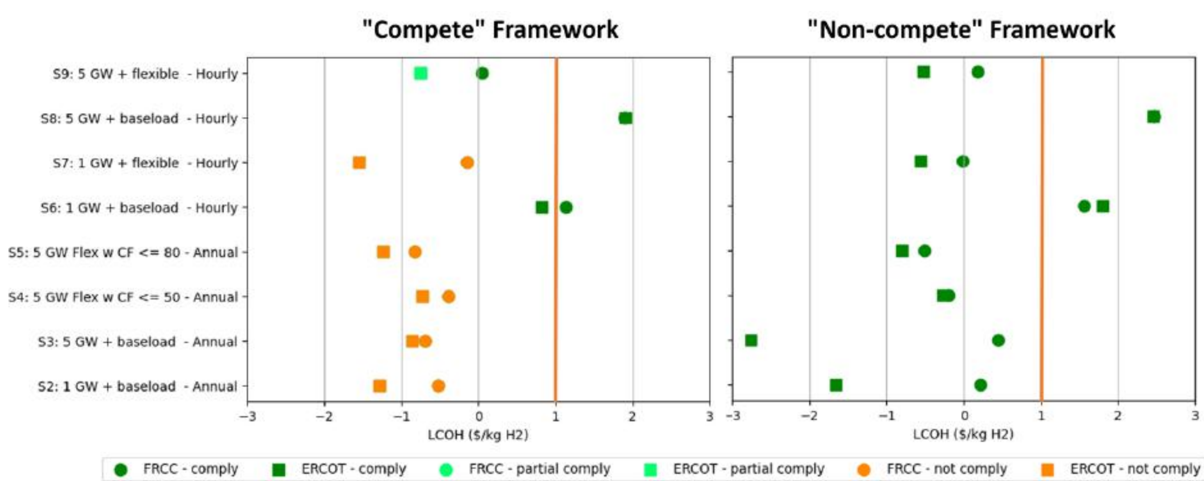

Figure 8. Levelized cost of hydrogen and compliance with the PTC emissions threshold under different scenarios for both additionality frameworks. Since consequential emissions cannot be assessed in practice, the \$3/kg H_2 was applied to LCOH in all

cases. The color of the data point indicates whether the PTC was correctly or incorrectly applied. Dark green indicates that the consequential emissions associated with a case were correctly applied (i.e., below the emissions threshold to receive the \$3/kg H_2 subsidy); light green indicates that the case met an intermediary PTC emissions threshold; orange indicates that the PTC was incorrectly applied to a case that did not exceed the highest PTC emissions threshold. ERCOT and FRCC LCOH markers are overlapping for case S8 under both additionality frameworks.

While the presented analysis reconciles the findings of the two papers [6], [7] that consider alternative additionality modeling frameworks, it leaves open an important question from a policy perspective: **which additionality framework is the most appropriate to consider when determining eligibility for the PTC?** To address this question, it is useful to keep in mind the scale of electrolytic H_2 deployment and the broader scale of H_2 use in the economy today. As of May 2022, installed and under-construction proton exchange membrane (PEM) electrolyzer capacity in the United States amounted to 621 MW (18.5 MW installed) [14], implying that 1 GW and 5 GW electricity-equivalent H_2 demand would represent roughly a 2X and 10X of national capacity. Moreover, in the near-term, demand for green H_2 is likely to originate from sectors where H_2 is already used today (e.g., ammonia production) and thus, be relatively small compared to the scale of electricity demand. For example, if 10% of U.S. H_2 consumption in 2021 (around 1 MT/year) were to immediately shift to consume electrolytic H_2, it would amount to around 54 TWh electricity consumption or ~1% of US electricity consumption as of 2021. At the same time, VRE deployments on the grid are likely to grow rapidly in the near-term, as evident from their dominance in the existing interconnection queue in many U.S. regions [15], as well as due to dedicated VRE incentives (e.g., the ITC or PTC) in the IRA. Thus, it may be reasonable to assume that the total VRE generation capacity to be added to the grid for non-H_2 related causes[10] is likely to be much larger than the VRE generation capacity to be contracted for H_2 production in the near-term, independent of the time matching requirement.

It can be argued that this near-term context, in which the relative demand for renewable electricity for electrolytic H_2 is small compared to the total additions of renewable energy, more closely resembles the "non-compete" framework for emissions accounting for H_2 production; we expect significant non-H_2 production related renewables to enter before seeing significantly large volumes of electrolytic H_2 to be produced. However, as demand for green H_2 grows, driven in part by demand stimulation from other policies (e.g., the H_2 Hubs proposal in the IRA) as well as availability of low LCOH H_2 (post PTC), it is likely that power sector resources contracted for H_2 production will grow in magnitude and increasingly compete with power sector resources that would be deployed for non-H_2 related causes. In this case, the "compete" framework for additionality will be more suitable to evaluate the consequential emissions impact of H_2 production.

The above interpretation would imply that less stringent annual time-matching requirements may be reasonable in the near-term to ensure minimal consequential emissions (Figure 4B) and would also lead to low LCOH outcomes (Figure 5B). While hourly time-matching with flexible operation can also achieve low consequential emissions and LCOH outcomes under the "non-compete" framework, its implementation would require much larger land area, onsite H_2 storage (for flexible operation), and capital investments than under annual time-matching. These requirements may constitute additional barriers for practical implementation. One such difficulty is the need to connect these renewable resources to the grid, in order for excess electricity to be sold to the grid and thus enable lower LCOH. These conditions would aggravate the existing interconnection queue issue and could hamper the kick-off of electrolytic H_2 production. In that

[10] Other sources of VRE deployment include grid decarbonization policy goals and bilateral power purchase power agreements signed by existing large consumers of electricity. For example, according to Bloomberg (https://about.bnef.com/blog/corporate-clean-energy-buying-tops-30gw-mark-in-record-year/), corporate clean energy procurements stood at 20.3 GW in 2021 in the U.S. as compared to 9.1 GW in 2018.

regard, requiring hourly time-matching in this decade may work against the policy objectives of the PTC to scale green H_2 production. In particular, in the near-term, achieving electrolyzer H_2 sales prices[11] that are lower than grey H_2 prices (~\$1/kg) and possibly even lower than natural gas reforming with CCS (including eligible H_2 PTC for that process) would encourage the deployment of electrolyzers, allowing for technology scale up and associated reductions in capital costs. Realizing such low prices for green H_2 would support long-term economy-wide decarbonization goals by stimulating new demand for H_2 in end uses that are currently dominated by fossil fuels (e.g., heavy-duty transport), as well as potentially displacing fossil fuel based H_2 in existing industrial applications.[12] In the case of the former, additional investments will be needed to facilitate H_2 use (e.g., refueling infrastructure, higher CAPEX equipment), and having very cheap H_2 in the short-term could create an added incentive for its use.

In the longer term (e.g., from 2030 onwards), shifting to hourly time-matching requirements as green H_2 demand grows may be necessary to avoid the risk of high consequential emissions impacts from annual time-matching, as VRE resources for H_2 production compete with VRE resources for grid decarbonization. Moreover, a phased approach for implementing more stringent hourly time-matching may also benefit from capital cost declines for power sector resources (VRE, battery storage) and electrolyzers that would make the LCOH outcomes for hourly time-matching more compelling than values estimated in this study. Collectively, these factors indicate that a phased approach on defining the qualifying requirements for the H_2 PTC may be the most pragmatic approach to minimize barriers to grid decarbonization while at the same time stimulating electrolytic H_2 use in difficult-to-decarbonize applications through the availability of low cost H_2 supply.

5. Conclusion

The United States' Inflation Reduction Act (IRA) includes a H_2 production tax credit (PTC) to subsidize low-carbon H_2 up to USD \$3/kg. However, it is difficult to assess the emissions intensity of H_2 production that contracts grid interconnected renewable electricity. In this paper, we focus on how results for different temporal matching requirements are conditional upon how additionality is modeled.

Our analysis is inspired by different modeling approaches adopted by recent papers that present conflicting results. Ricks et al. measures the change in emissions intensity associated with H_2 in a model where H_2 electrolysis demand is co-optimized with the grid — i.e., H_2 production "competes" with expansion. In contrast, Zeyen et al. first allows the grid to expand to the optimal generation mix, before introducing the H_2 load and optimizing resources to meet it — i.e., H_2 production does not "compete" with grid expansion.

We have contrasted both modeling frameworks for two case studies: the FRCC and ERCOT grids, both for 2021. Our key finding is that we confirm that the consequential emissions from producing electrolytic H_2 are conditional upon how the additionality requirement is modeled. Under the "compete" framework, an hourly time-matching requirement is the only possible way to reach consequential emissions under the threshold needed to receive any PTC (and not even all analyzed hourly time-matching scenarios this is guaranteed). In contrast, under the "non-compete" framework annual time-matching requirements are sufficient in all cases to meet the threshold needed to receive the highest \$3/kg PTC. Another important finding, which is aligned with the existing literature is that independent of the additionality modeling

[11] The actual selling price of the electrolytic H_2 will be higher than LCOH to account for producer return on investment and additional taxes, both of which were not considered here.

[12] For displacing fossil-based H_2 in existing applications, the LCOH of electrolytic H_2 has to match or be lower than the marginal cost of natural gas reforming based H_2 since many of those facilities may have fully paid off their capital costs.

framework an hourly time-matching requirement leads to higher LCOH compared to annual time-matching requirements (excluding the attribution of a PTC). However, we find that the increase in LCOH is $0.10-$5.21/kg, which is greater than the $0-1/kg increase between hourly time-matching and no requirements reported by Ricks et al.[13] Significantly higher capacities of renewables need to be installed under the hourly time-matching requirement and thus more capital and space is required and possibly more H_2 storage (for flexible operation).

Finally, we have argued that since the demand for green H_2 is still relatively small today and VRE deployment continues to grow, the current context more strongly resembles a "non-compete" framework in which low consequential emissions impacts with annual time-matching are likely. However, with declining electrolyzer capital costs, as demand for green H_2 grows, the risk of higher consequential emissions impacts increases under annual time-matching, as the paradigm shifts to exhibit characteristics of the modeled "compete" framework. Hence, we argue for a "phased approach" in the requirements for the attribution of the PTC: a) annual matching in the near term to kick-off electrolytic H_2 production and b) and a deeper evaluation based on further modeling considering different levels of non-H_2 VRE deployment and green H_2 demand for various regions, to understand the timing of transition to hourly time-matching. Further research is required to quantify when a transition between time matching requirement regimes would be necessary.

In case an annual matching requirement would be implemented, we found that having a maximum capacity factor for the electrolyzer is an effective measure to minimize the risk of increasing consequential emissions due to the electrolytic H_2 production. Such a measure is pragmatic as in reality consequential emissions cannot be observed. Flexible operation of the electrolyzer may also reduce LCOH and lower the total capital investment required. Future research can investigate in more depth what an optimal upper limit for the capacity factor of the electrolyzer would be. The optimal upper limit will be a function of the context, e.g., the volume and marginal cost of coal versus gas-fired generation. Finally, in this paper we did not cover spatial matching requirements. Independent of hourly or annual matching requirements, it is important that congestion between the electrolyzer and the contracted renewables is limited. This topic may be explored in more depth in future work.

Acknowledgements

This work was funded by the Future Energy Systems Center at the MIT Energy Initiative. We gratefully acknowledge feedback from John Parsons, Robert Stoner, and Randall Field.

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Supporting Information

S1. Modeling data inputs

This section summarizes the major data inputs used in the modeling. Unless otherwise stated, all costs have been converted to 2021 USD. summarizes the cost assumptions for VRE and Li-ion battery storage resources. The parametrization of battery storage also considers a self-discharge rate of 0.002% per hour [16]. The model can independently vary the installed energy capacity and power capacity for Li-ion storage so long as the ratio of energy capacity to power capacity (i.e., duration) is between 0.15 -12 hours. Table S2 summarizes cost assumptions for electrolyzers and H_2 storage.

S1.1 Cost assumptions

Table S1. Generation technology cost and performance parameters. A discount rate of 4% is used to annualize investment costs. Reported annualized cost account for the investment tax credit (ITC) for wind, solar and battery storage deployments, which as per the Inflation reduction act is set to be 30%. Data corresponds to 2022 costs reported by the NREL Annual Technology Baseline 2022 edition [17].

Technology	Lifetime (years)	Investment cost – power ($/MW)		Annualized CAPEX w/ ITC – Power ($/MW/year)	Investment cost – energy ($/MWh)		Annualized CAPEX w/ ITC– Energy ($/MWh/year)	Fixed operation and maintenance cost		Variable operating cost ($/MWh)
		W/o ITC	W ITC		W/o ITC	W/o ITC		Power ($/MW/year)	Energy ($/MWh/year)	
Solar PV	30	1176,000	823,200	52,105	-	-	52,105	22,721	-	0
Onshore wind	30	1428,000	999,600	56,185	-	-	56,185	17,781	-	0
Li-ion battery storage	15	255,150	178,605	16,064	296,100	207,270	18642	6379	7403	1[14]

Table S2. Electrolyzer and H_2 storage technology cost and performance parameters. A discount rate of 4% is used to annualize investment costs. Data sourced from NREL H_2A analysis and other literature [18] [19]. The cost of feedwater for electrolyzer is relatively small compared to the cost of energy and thus is ignored in the analysis.

Technology	Lifetime	Investment cost		Annualized investment cost		Fixed operation and maintenance cost - power($/MWe/year)	Specific electrical power consumption (MWh/tonne)
		Power ($/MWe)	Energy ($/tonne H_2)	Power ($/MWe/year)	Energy ($/tonne H_2/year)		
Electrolyzer	20	1189,440	-	87,521		17,557	54.3
H_2 storage (tank)	30		587	-	33,929	-	-
H_2 storage compressor	15	2451,496	-	220,490		-	0.71

[14] To avoid instances of battery charging and discharging simultaneously, which is possible in a capacity expansion model formulated as linear program (LP), we penalize battery charging and discharging with a small but non-zero variable operating cost.

The model runs were based on fuel price assumptions based on 2019 rather than 2022, as summarized in Table S3, so as to not consider the short-term distortion in fuel prices resulting from the Russian invasion of Ukraine. While the spot prices of natural gas through 2021 were much higher than 2019 values (as high as $6/MMBtu), it is interesting to note that prices in early 2023 have come down to levels seen in 2019[15]. Table S4 summarizes power capacity in GW by resource type for FRCC and ERCOT in 2021.

Table S3. Fuel price assumptions for FRCC 2021 and ERCOT 2021 case studies. Data sourced from EIA Annual Energy Outlook 2022 [20] for 2021 prices. Natural gas and coal modeled with combustion CO2 emissions factors of 0.05306 tCO2/MMBtu and 0.09552 tCO2/MMBtu, respectively.

Fuel	FRCC 2021	ERCOT 2021
Natural gas	4.15	2.03
Coal	3.37	2.47
Uranium (for nuclear)	0.71	0.70

Table S4. Existing power capacity in GW as of 2021 for FRCC and ERCOT 2021. Generators clusters and technical characteristics (e.g., heat rate) were adapted from 2019 data sourced from PowerGenome [21] to match the 2021 capacity as reported by EIA [20]. Diurnal battery storage is assumed to have an energy capacity corresponding to a rated duration of 4 hours.

	FRCC 2021	ERCOT 2021
Coal	5.4	14.4
Natural gas combined cycle	31.1	35.1
Natural gas combustion turbine	10.2	7.0
Nuclear	3.7	5.0
NG steam turbine	4.1	10.8
Biomass	0.3	0.1
Hydro	0.04	0.5
Solar	4.8	9.1
Wind (onshore)	0.0	34.1
Diurnal battery storage	0.45	0.7

S1.2. Load and generation resource characterization

Table S5 summarizes the key assumptions for characterizing electricity power demand and electricity resources for the two regional case studies. The electricity demand data was obtained from PowerGenome [21] and corresponds to demand for 2021 for the two regions. Figure S1 visualizes the hourly demand profile and VRE resource profile for FRCC, which highlights how wind availability tends to be low during summer months when electricity demand is relatively high. Figure S2 visualizes the VRE resource and demand data for ERCOT, with wind exhibiting less seasonal variation than in FRCC.

Table S5. Characterization of electricity demand, variable renewable energy (VRE) resource availability and availability factors for other resources in the system. Availability factors refers to the fraction of nameplate capacity of the resource that can be utilized in each hour. For VRE resources, the availability factor, also known as capacity factor, varies from one hour to the next depending on weather conditions. In our modeling for we assume constant availability factors for other resources, although these resources may also have unforced outages that could impact their hourly availability in practice. Power demand data was generated by

[15] For example, according to the data from the U.S. Energy Information Administration (https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm), the Henry hub spot price in Jan and Feb 2023 were 3.27$/MMBtu and $2.38/MMBtu, respectively.

multiplying each hour of a 2019 demand profile generated by PowerGenome [21] by a scalar, so that total annual power demand equaled the annual demand reported in the 2022 EIA AEO report.

	FRCC 2021	ERCOT 2021
Peak power demand (GW)	48.3	75.7
Annual power demand (TWh)	245.9	388.9
Annual average capacity factor: onshore wind:	30.6%	46.3%
Annual average capacity factor: solar PV	26.6%	29.4%
Hourly availability factor for various resources		
Coal, natural gas, and biomass	90%	
Nuclear	95%	
Battery	100%	
Electrolyzers	95%	

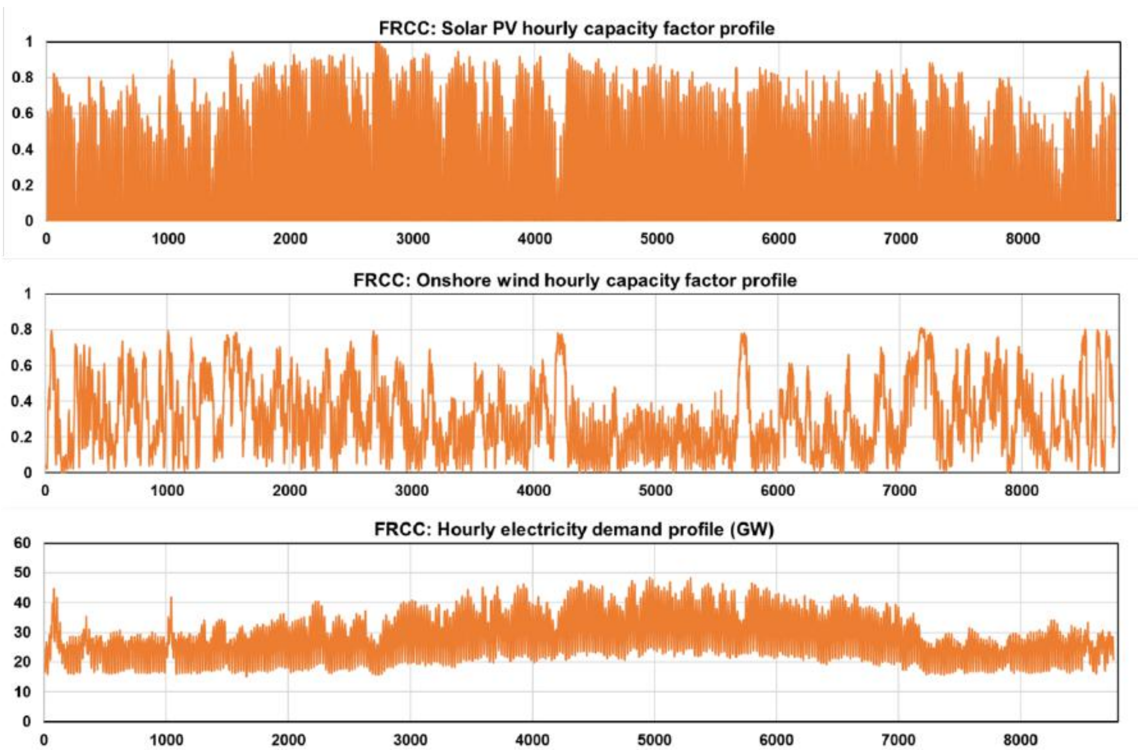

Figure S1. Hourly resource availability profiles solar PV (top row) and onshore wind (middle row) as well as hourly electricity demand profile (bottom row) for FRCC 2021 case study. Details about the data inputs discussed in section S1.2

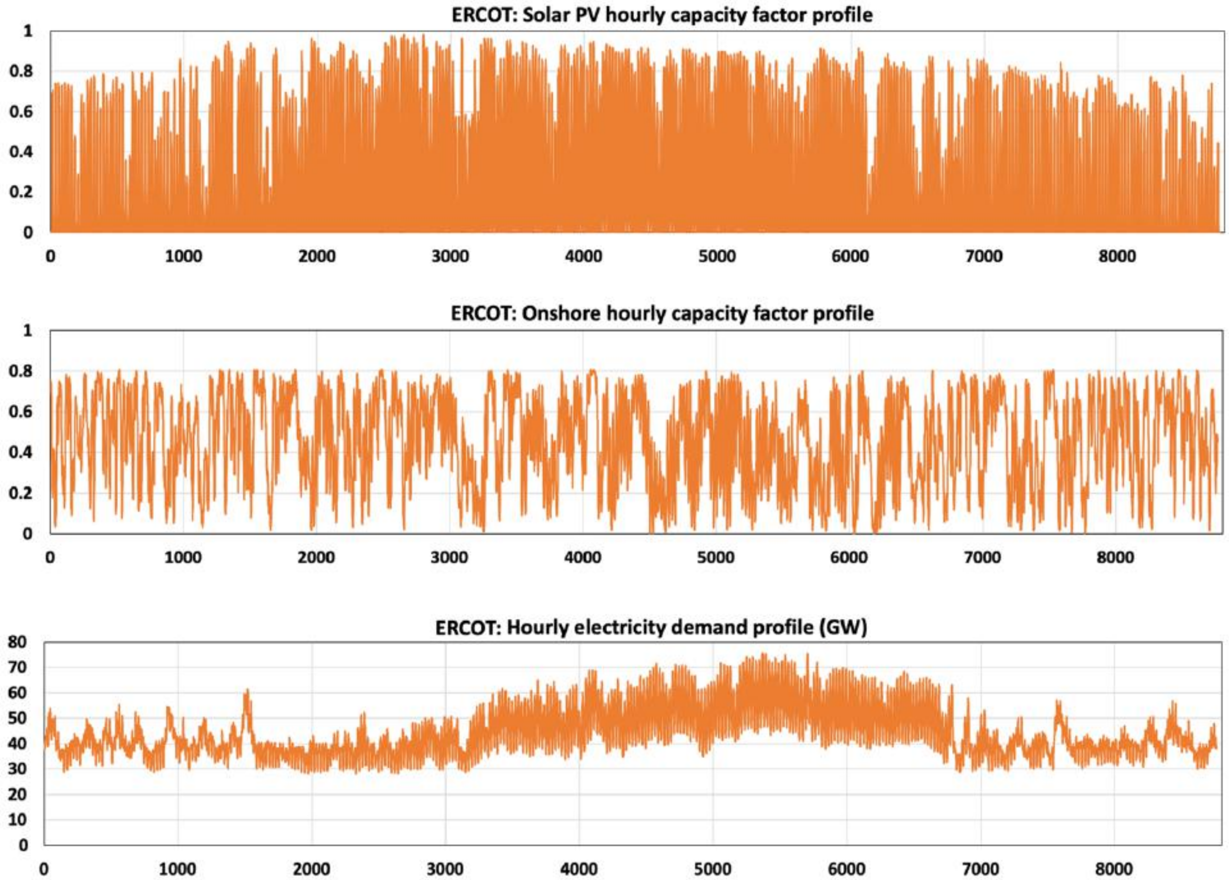

Figure S2. Hourly resource availability profiles solar PV (top row) and onshore wind (middle row) as well as hourly electricity demand profile (bottom row) for ERCOT 2021 case study. Details about the data inputs discussed in section S1.2

Hourly resource availability data for onshore wind and solar PV for each region was generated by averaging hourly resource availability profiles for weather year 2012 from multiple sites, available from a previous study [22]. The site-level data for PV was simulated using site-level irradiation data from the National Solar Radiation Database in conjunction with the open-source PVLIB. In the case of wind, the site-level resource data was simulated using site-level wind speed data from the NREL Wind Integration National Dataset Toolkit and a power curve data based on the Gamesa G26/2500 wind turbine. Further details about the site-level data calculation are provided in the supporting information of a previous publication [22]. Figure S3Figure S3 shows the geographic areas used to compute average capacity factors for wind and solar generation in FRCC and ERCOT. The regional-level wind and solar availability profiles for FRCC were generated by averaging resource availability profiles over the entire FRCC service territory. In the case of ERCOT, we only considered sites in West Texas and the Panhandle, to account for the fact that this region has the highest quality renewable resources and, thus, is likely to dominate new resource deployment (and already dominates existing resource deployment).

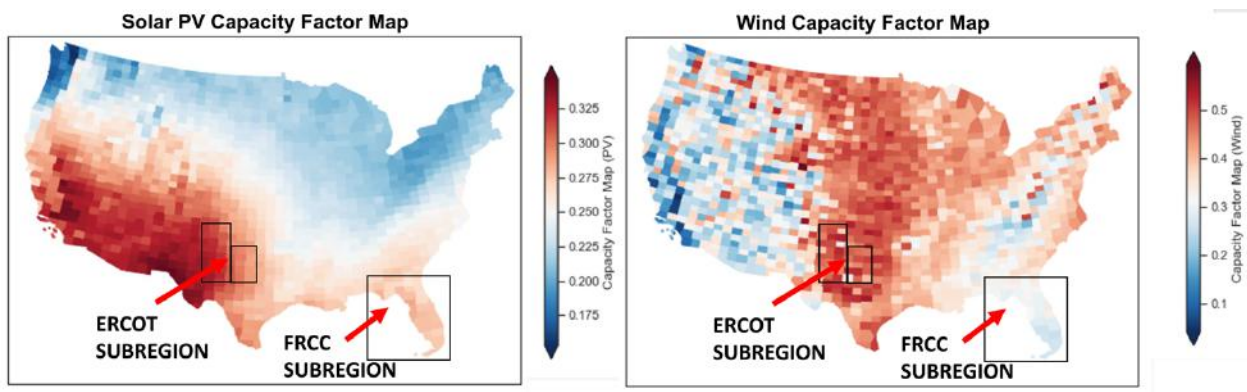

Figure S3. Sub-regions for computing hourly capacity factors for solar and wind resources in ERCOT and FRCC. This figure is an adaptation of Figure S2 from [22], which shows average annual capacity factors computed according to 2012 weather data. To compute hourly capacity factors for this paper, we average hourly capacity factors for the coordinate blocks in the highlighted regions.

S2 Key model constraints

<u>Hourly H_2 supply-demand balance</u>

Equation S1 enforces that sum of H_2 production (gen_t^{Ely}) plus net discharge of H_2 storage ($dischg_t^{H2} - chg_t^{H2}$), if available, must equal the exogeneous hourly H_2 demand (δ_t^{H2}) for all hours of the year.

$$gen_t^{Ely} + dischg_t^{H2} - chg_t^{H2} = \delta_t^{H2} \qquad \forall t \in T \qquad \text{(S1)}$$

<u>Annual time-matching requirement</u>

Equation S2 starts that sum of contracted hourly VRE generation ($gen_{g,t}^{VRE}$) from eligible set of renewable resources (ESR_g) throughout the year must be at least equal to annual electrolyzer load.

$$\sum_{g \in ESR^g} \sum_{t \in T} gen_{g,t}^{VRE} = \sum_{t\ in\ T} \delta_t^{H2} \qquad \text{(S2)}$$

<u>Hourly time-matching requirement</u>

The hourly time-matching requirement constraint enforces that for every hour of the year, the electrolyzer power consumption, equal to product of its generation times the specific power consumption (λ^{Ely}), must be less than or equal to generation from the contracted set of VRE generation (ESR_g) + net injection from eligible battery storage (ESR_b). This ensures that new electrolyzer load is accounted for by these additional resources at each hour. If electrolyzer operation is baseload than $gen_t^{Ely} \lambda^{Ely} = Demand_t^{H2}$.

$$\sum_{g \in ESR^g} gen_{g,t}^{VRE} + \sum_{k \in ESR^b} \left(dischg_{k,t}^{bat} - chg_{k,t}^{bat} \right) \geq gen_t^{Ely} \lambda^{Ely}\ for\ all\ t \in T \qquad \text{(S3)}$$

At each time step, the amount charged by the new battery resource (part of set ESR_b) cannot exceed maximum available generation from set of eligible renewable resources (part of set ESR_g), defined as the sum of the hourly capacity factor ($\alpha_{g,t}^{VRE}$) times the installed capacity (Cap_g^{VRE}). This ensures that the battery is charging only when procured renewable energy is available.

$$chg_{k,t}^{bat} \leq \sum_{g \in ESR_g} \alpha_{g,t}^{VRE} \times Cap_g^{VRE} \ \forall \, t \in T \,, k \in ESR_b \tag{S4}$$

Electrolyzer maximum annual capacity factor

When modeling the variant of the annual time-matching requirement with a maximum annual capacity factor limit ($\alpha^{ELY,Max}$), we include Equation S5 in the model. The constraint effectively translates into a minimum electrolyzer capacity deployment constraint for an exogeneous annual H_2 demand that is equal to t. β^{ELY} in Equation S5 refers to the availability factor for the electrolyzer, which denotes the fraction of installed capacity that is available for production in any hour.

$$\frac{1}{8760} \sum_{t \; in \; T} Demand_t^{H2} \leq \; \alpha^{ELY,Max} \times \beta^{ELY} \times Cap_g^{VRE} \ \forall \, t \in T \,, k \in ESR_b \tag{S5}$$

S3 Additional results for FRCC 2021

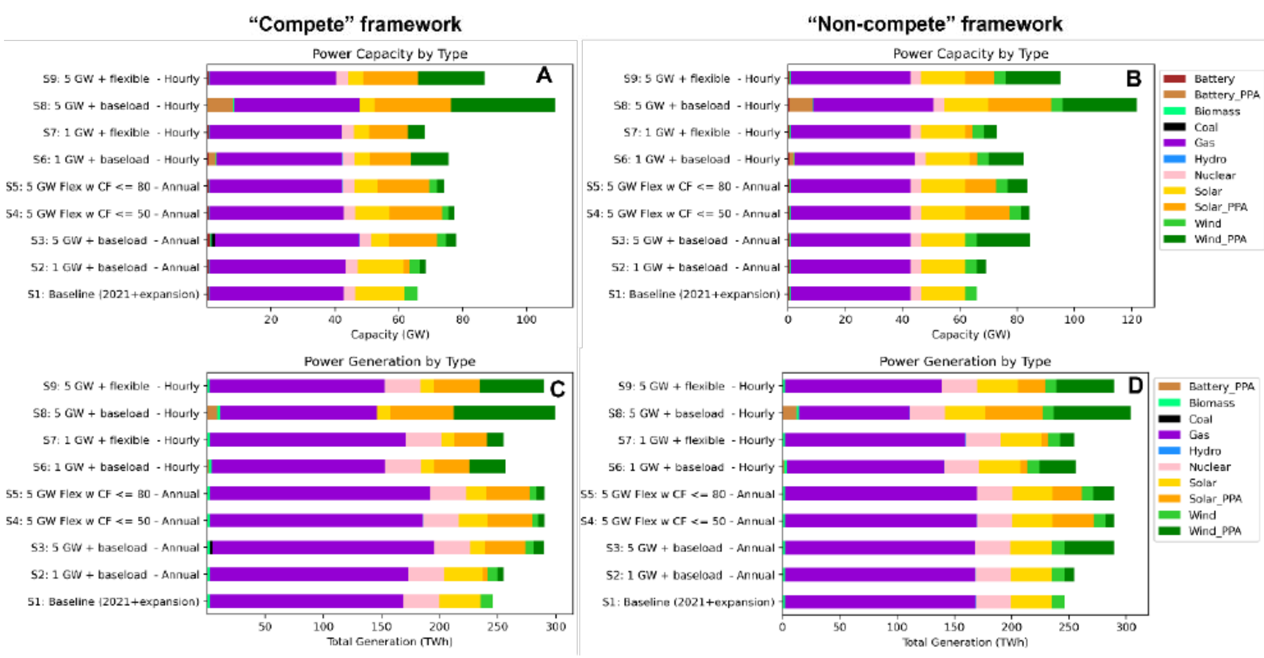

Figure S4. Power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality definitions. Results correspond to FRCC 2021 case study Also shown are the results for the baseline scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

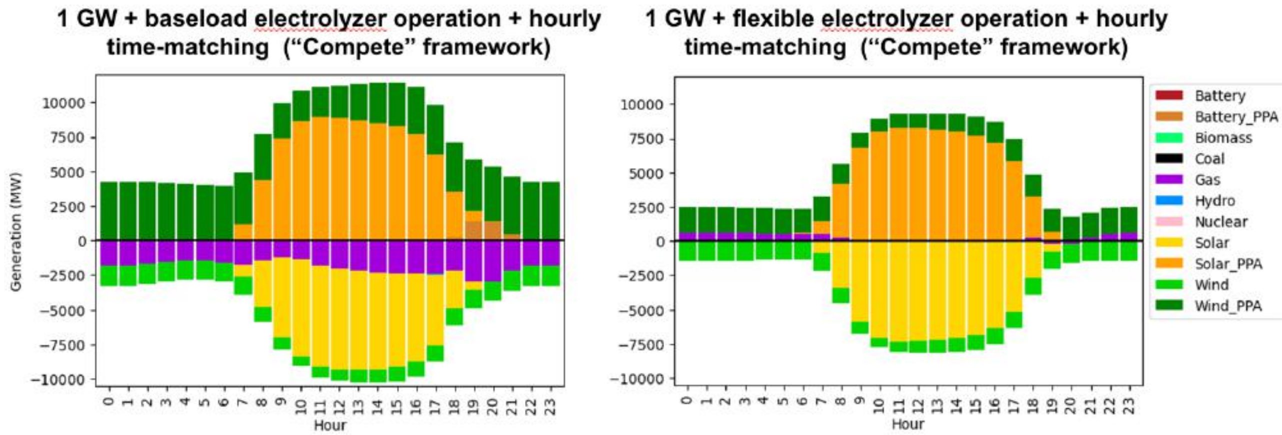

Figure S5. Average hourly change in power system dispatch between cases with H_2 production vs. baseline in FRCC 2021 for the scenarios with 1 GW H_2 demand, hourly time-matching requirements, "Compete" additionality framework and baseload electrolyzer operation (1st column) or flexible electrolyzer operation (2nd column).

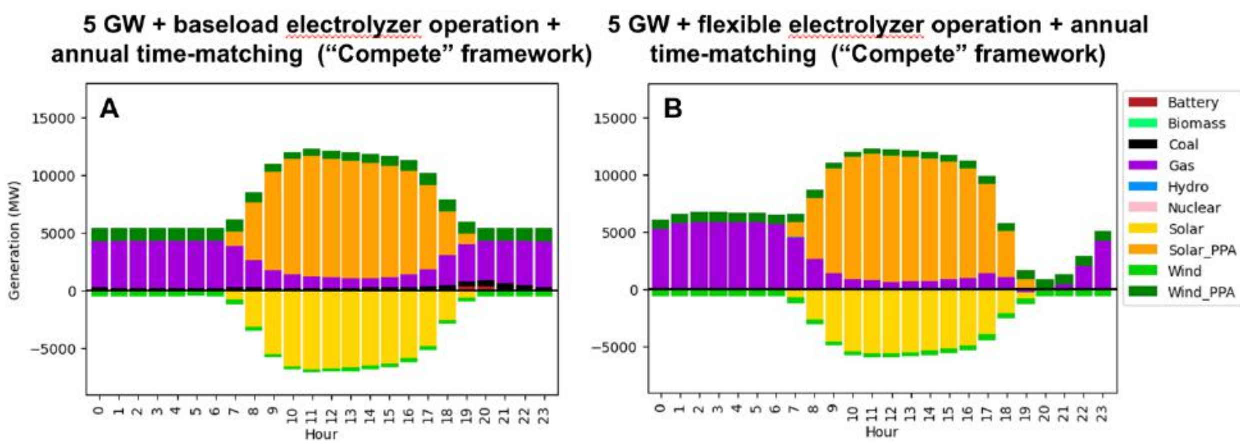

Figure S6. Average hourly change in power system dispatch between cases with H_2 production vs. baseline in FRCC 2021 for the scenarios with 5 GW H_2 demand, annual time-matching requirements, "Compete" additionality framework and baseload electrolyzer operation (1st column) or flexible electrolyzer operation (2nd column). The annual flexible operation case is with an annual electrolyzer capacity of >=80%.

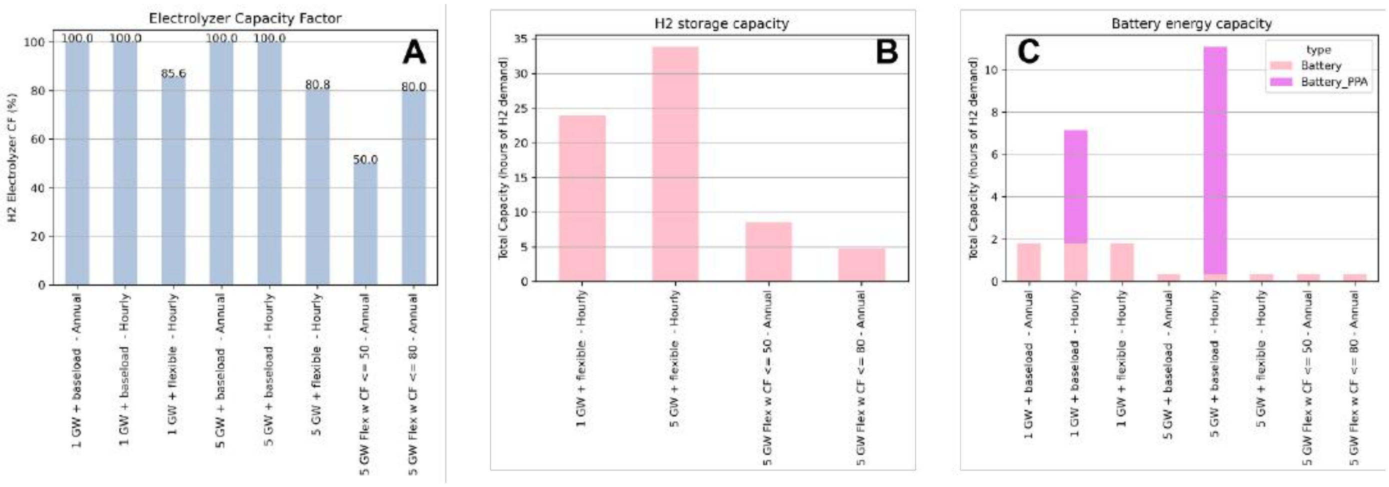

Figure S7. Electrolyzer capacity factor (A), H_2 storage capacity (B) and Battery energy capacity (C) for alternative H_2 demand scenarios, time-matching requirements under the "Compete" additionality framework. Results correspond to FRCC 2021 case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.

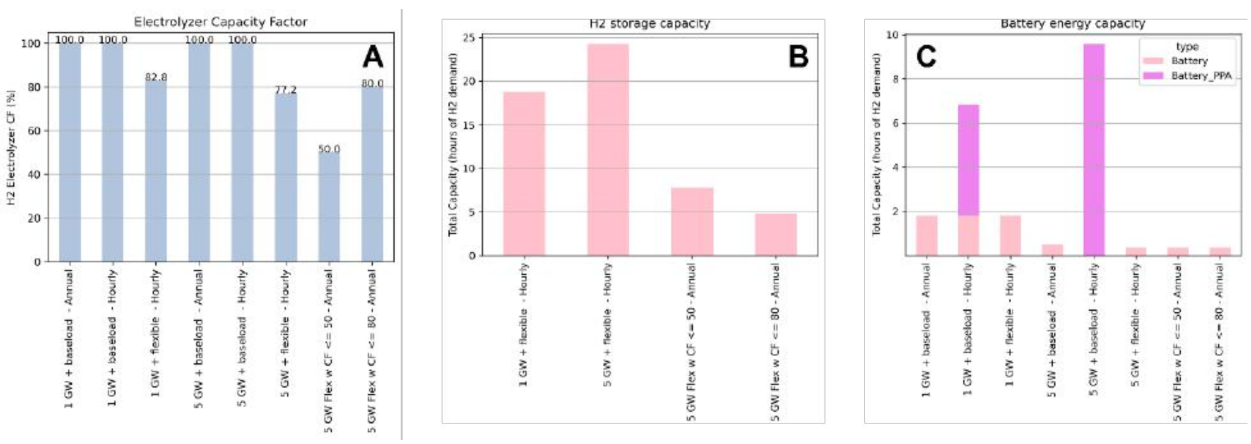

Figure S8. Electrolyzer capacity factor (A), H_2 storage capacity (B) and Battery energy capacity (C) for alternative H_2 demand scenarios, time-matching requirements under the "Non-compete" additionality framework. Results correspond to FRCC 2021 case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.

S4 Additional results for ERCOT 2021

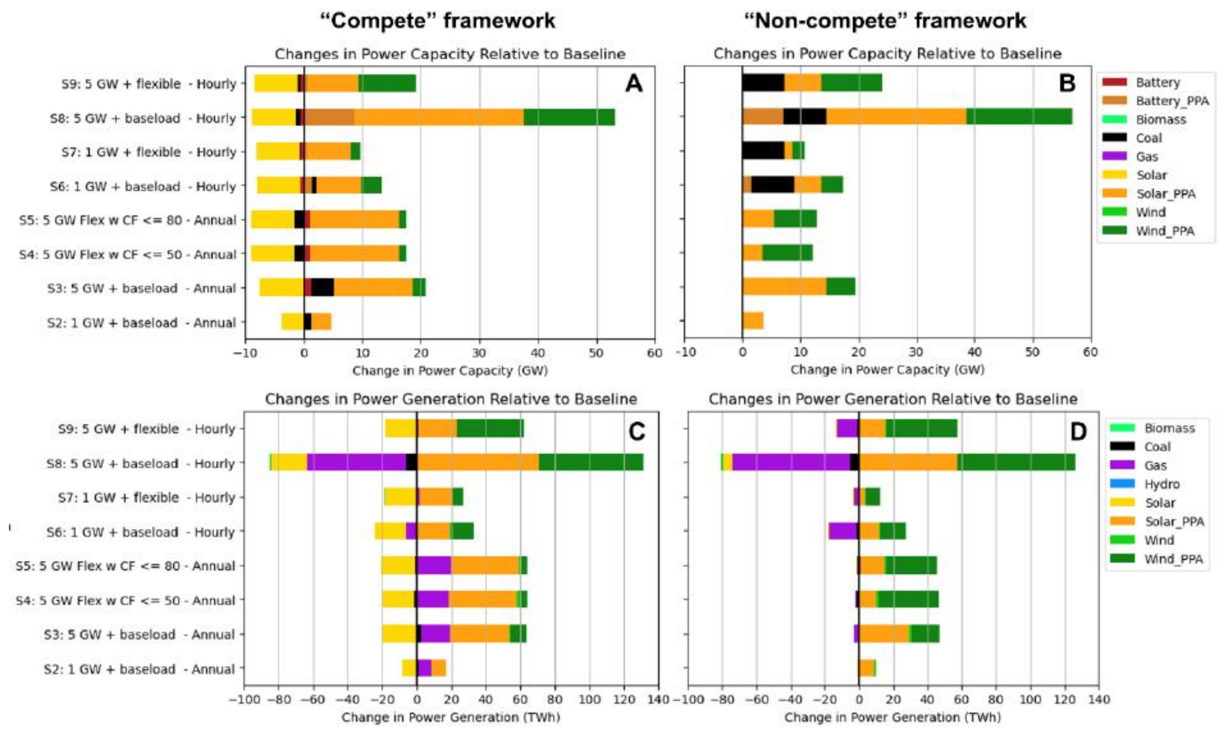

Figure S9. Change in power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality definitions. Results correspond to ERCOT 2021 case study and are reported relative to the baseline scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

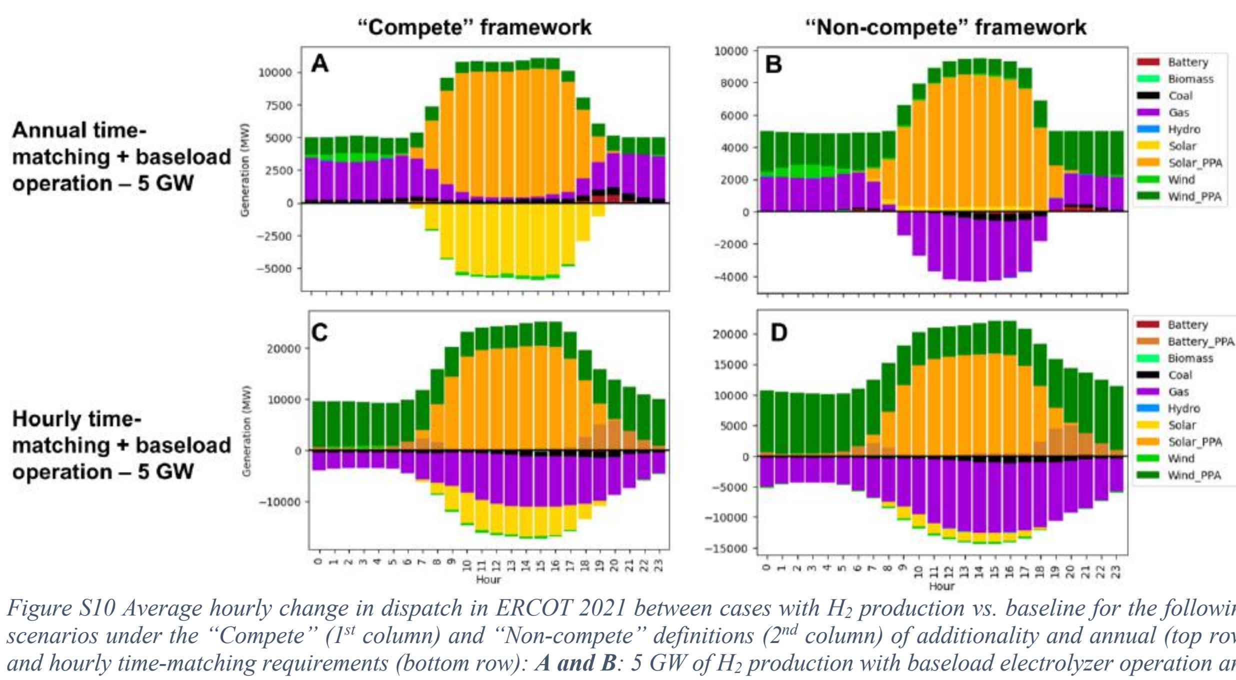

*Figure S10 Average hourly change in dispatch in ERCOT 2021 between cases with H_2 production vs. baseline for the following scenarios under the "Compete" (1st column) and "Non-compete" definitions (2nd column) of additionality and annual (top row) and hourly time-matching requirements (bottom row): **A and B**: 5 GW of H_2 production with baseload electrolyzer operation and annual time-matching requirements. **C and D**: 5 GW of H_2 production with baseload electrolyzer operation and hourly time-matching requirements.*

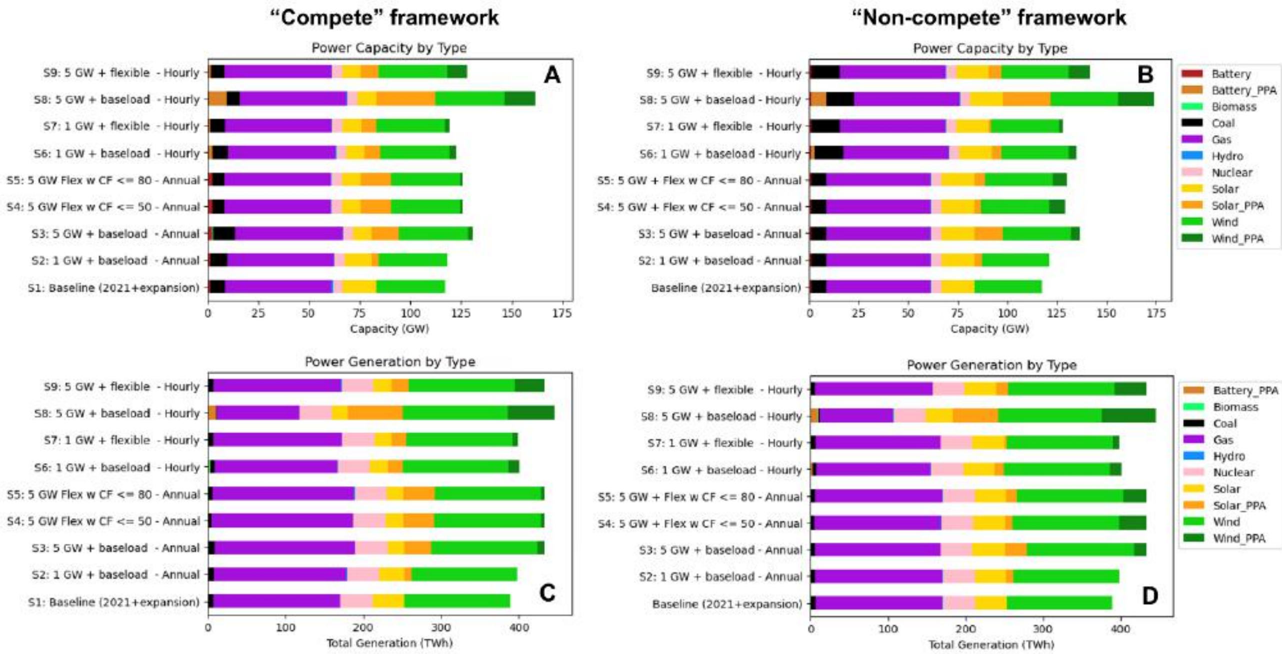

Figure S11. Power generation and storage capacity (top row, A-B) and annual power generation (bottom row, C-D) resulting from electrolytic H_2 production under alternative H_2 demand scenarios, time-matching requirements, and additionality definitions. Results correspond to ERCOT 2021 case study. Also shown are the results for the baseline scenario involving grid resource expansion without any H_2 demand, as defined in Figure 1.

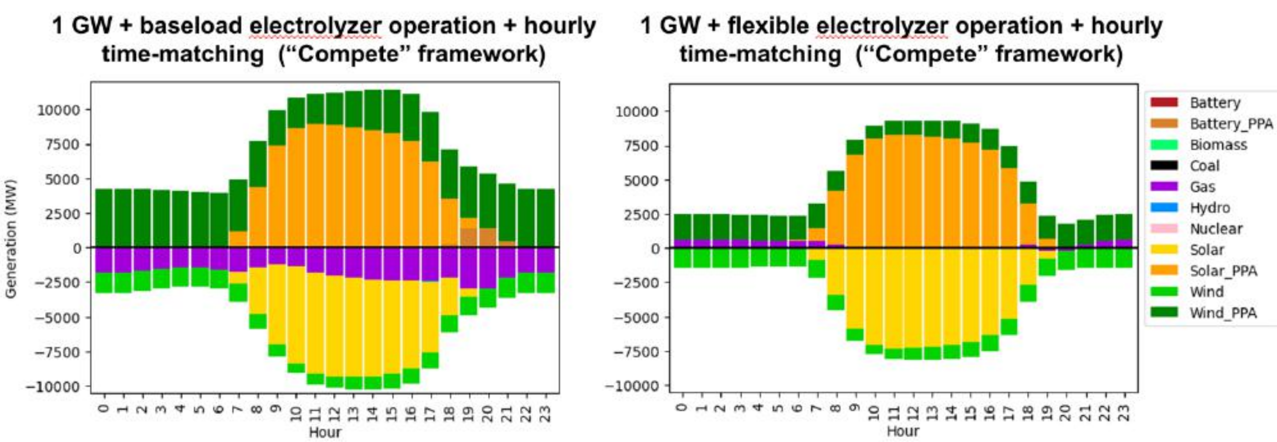

Figure S12. Average hourly change in power system dispatch between cases with H_2 production vs. baseline in ERCOT 2021 for the scenarios with 1 GW H_2 demand and hourly time-matching requirements, "Compete" additionality framework and baseload electrolyzer operation (1st column) or flexible electrolyzer operation (2nd column).

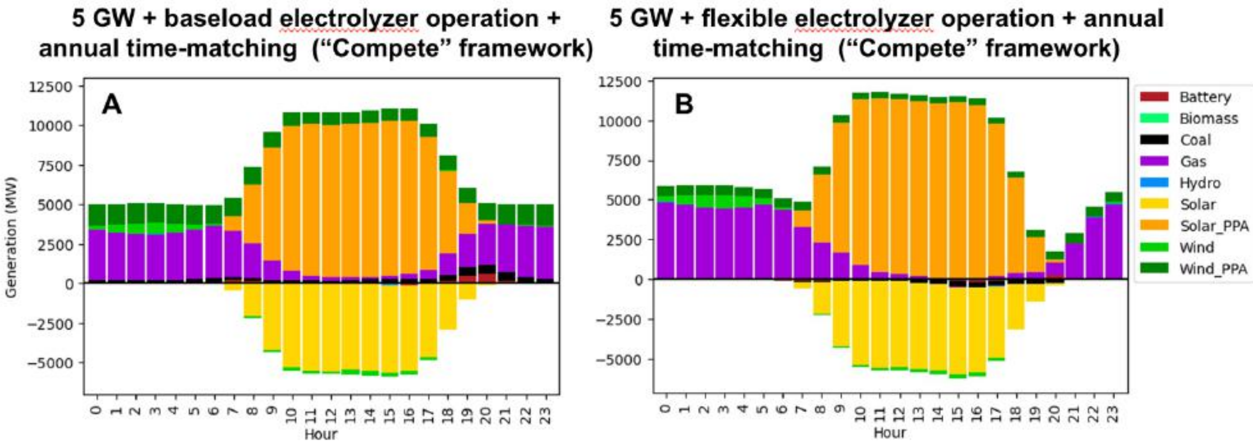

Figure S13. Average hourly change in power system dispatch between cases with H_2 production vs. baseline in ERCOT 2021 for the scenarios with 5 GW H_2 demand, annual time-matching requirements, "Compete" additionality framework and baseload electrolyzer operation (1^{st} column) or flexible electrolyzer operation (2^{nd} column). The annual flexible operation case is with an annual electrolyzer capacity of >=80%.

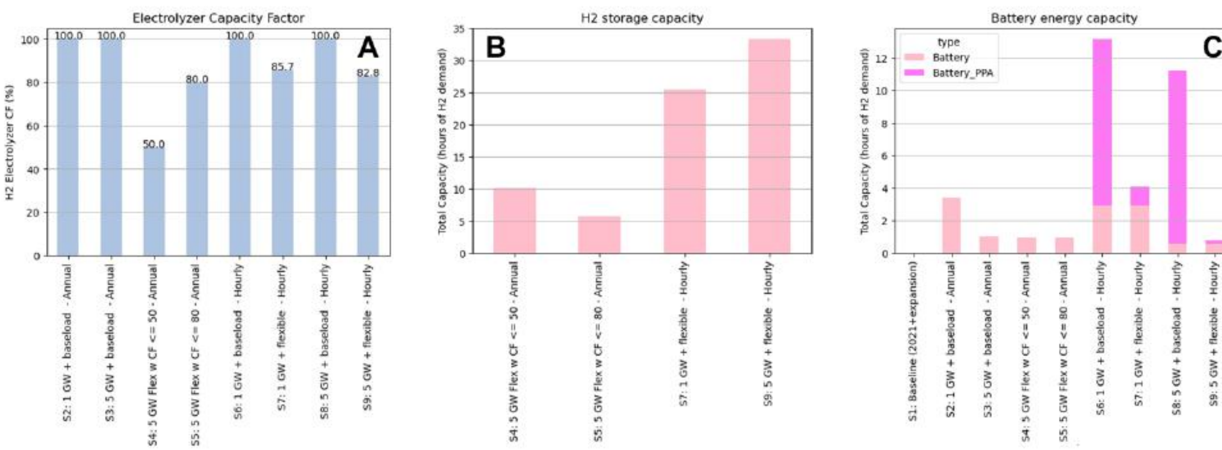

Figure S 14. Electrolyzer capacity factor (A), H_2 storage capacity (B) and Battery energy capacity (C) for alternative H_2 demand scenarios, time-matching requirements under the "Compete" additionality framework. Results correspond to ERCOT 2021 case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.

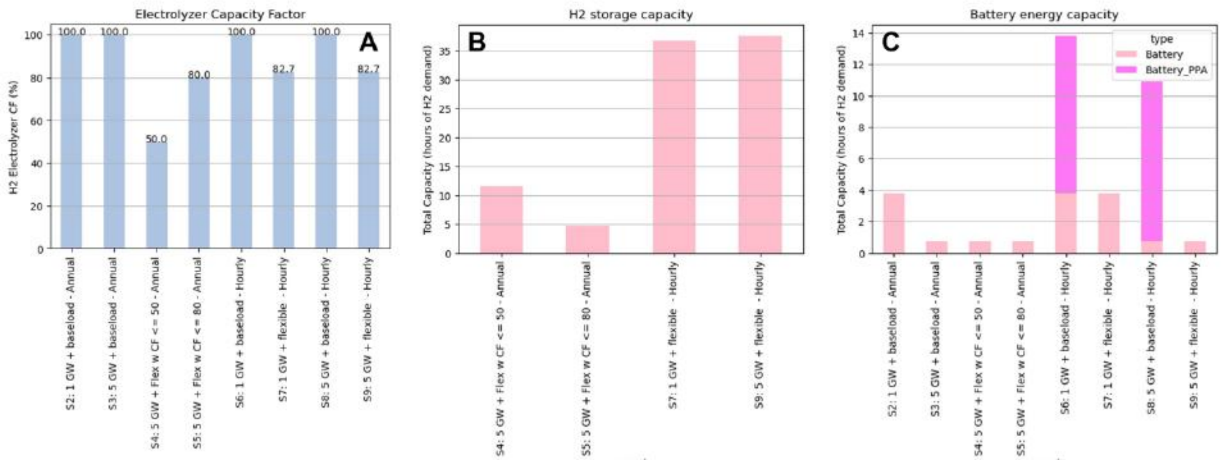

Figure S 15. Electrolyzer capacity factor (A), H_2 storage capacity (B) and Battery energy capacity (C) for alternative H_2 demand scenarios, time-matching requirements under the "Non-compete" additionality framework. Results correspond to ERCOT 2021 case study. H_2 and battery storage capacity reported in terms of hours of exogeneous H_2 demand that can be met with the available storage capacity when full. Electrolyzer capacity factor calculated based on available capacity in each hour, which is 95% of the installed capacity.