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# Green and low-carbon hydrogen - the impact of classification rules and subsidies on asset sizing and energy sourcing for electrolytic hydrogen production.

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**Abstract**—The production of green hydrogen from renewable energy and water by electrolysis is considered an important technology for decarbonation of many industries. To improve the competitiveness of this burgeoning industry, many jurisdictions are introducing incentive programs, including Europe, the US, and Australia. Eligibility for these incentives is linked to electricity sourcing rules to promote the use of renewable and low-carbon sources. However, definitions of green and low-carbon hydrogen vary between jurisdictions. One key difference is the measurement of temporal correlation between renewable sources and electrolyser consumption, with hourly, monthly, and yearly time-matching proposed. Furthermore, certain regions with cleaner grid mixes may have the option to produce low-carbon hydrogen without adherence to these rules. This paper studies the impact of these differing green and low-carbon classification rules on sourcing strategy, equipment sizing, final cost, and grid emissions exposure of the produced hydrogen. A market-focused 2-stage stochastic model of a green hydrogen producer supplying a hydrogen demand is used, with uncertainty in renewable production and electricity spot market prices. Strict hourly time-matching is observed to increase demand for diversified power purchase agreement (PPA) portfolios, and require greater electrolyser and hydrogen storage capacities. For carbon-intensive grids, less strict time matching rules can lead to the produced hydrogen being classified as 100% green whilst exceeding intended maximum emissions intensities.

**Index Terms**—Hydrogen, renewable, energy, market, futures, stochastic, optimization, capacity, planning, uncertainty, power-to-gas, power-to-x, time matching.

## I. INTRODUCTION

As part of the energy transition and the fight against climate change, using green hydrogen produced from water and renewable energy through electrolysis is seen as a promising way to reduce emissions in hard-to-decarbonize sectors [1]. However, in the medium-term, green hydrogen is likely to remain costlier than cheaper, polluting technologies,

making it harder to secure offtake agreements with long-term consumers [2].

To improve the competitiveness of low-carbon and green hydrogen, many jurisdictions are introducing per-kilo production incentives. In the US, the Inflation Reduction Act's 45V Hydrogen Production Tax Credit [3] provides up to 3\$/kg, depending on carbon intensity. The EU's Hydrogen Bank [4] offers subsidies up to 4.5€/kg. A 2\$/kg tax incentive is proposed in Australia [5] with additional funding to be provided through an auction process [6].

Future hydrogen production has the potential to significantly increase electrical demand. To prevent this new demand from relying on carbon-intensive sources or diverting existing clean energy sources from their current role of decarbonizing electricity consumption, new incentives are tied to energy and emissions accounting rules. These rules can be viewed through the prism of the *three pillars* of green hydrogen energy sourcing:

- *Additionality* - the origins of the renewable energy being from newly developed parks,
- *Geographic Correlation* - the renewable energy produced being physically deliverable to the electrical demand for hydrogen production (ie. unconstrained by transmission and/or separate pricing systems), and
- *Temporal Correlation* - the time-matching between the production of hydrogen and the generation of the renewable electricity procured.

From the perspective of a single project proponent, additionality and geographic correlation rules can be considered to be integrated into the price of renewable Power Purchase Agreements (PPA's) that are available in the project location. This study focuses on the third requirement: temporal correlation.

In the US, the 45V tax credit requires strict hourly time-matching [3], with annual time-matching permitted for first-movers until the end of 2027. Europe’s green hydrogen RFNBO definition (Renewable Fuel of Non-Biological Origin [7]) also mandates hourly time matching, though after 2030, with monthly time-matching allowed until then. Yearly time-matching is effectively allowed within the Australian programs [5], [6].

The schemes also take a different view around *low-carbon* hydrogen (a different product to renewable green hydrogen). The US considers hydrogen with less than 4kgCO<sub>2</sub>/kgH<sub>2</sub> as low-carbon, attracting a lower subsidy of 0.6\$/kg. In Europe the RFNBO classification is intended for green hydrogen (ie. hydrogen produced from renewables), and is currently the only classification eligible for subsidies. However it has denoted 3.384kgCO<sub>2</sub>/kgH<sub>2</sub> as its limit for an upcoming low-carbon hydrogen classification [8]. In bidding zones with a low carbon intensity but low renewable penetration (such as France), market-sourced electricity is likely to be able to be used to produce this low-carbon alternative [7]. Hydrogen classification is under public consultation in Australia, although an intended limit of 0.6kgCO<sub>2</sub>/kgH<sub>2</sub> has been proposed for green hydrogen [5].

Low-carbon classifications are expected to be acceptable for most potential customers, however they do not attract the higher level of subsidies of green hydrogen. Given that obtaining green hydrogen subsidies may be necessary for enabling investment, and eligibility is tied to energy procurement strategy, modelling these subsidies is important for project planning. This paper explores the impacts of different incentive rules on equipment sizing and energy hedging for a producer of green and low-carbon hydrogen.

## II. LITERATURE REVIEW

An early study [9] on the impacts of different types of temporal correlation on electrolyser dispatching uses a Monte Carlo analysis for a fixed electrolyser capacity with day-ahead and intraday market access, and wind power. It finds stricter temporal correlation reduces emissions but also revenue.

Several system-level studies [10]–[13] analyse a variety of classification rules with a variety of metrics using deterministic capacity expansion models, however as price-maker models they are not appropriate for obtaining the decisions of a single producer.

In [14] a capacity expansion model for a price-taker agent is used to perform a sensitivity analysis of hydrogen cost and emissions intensity with respect to average grid costs and under various regulatory assumptions, however it is performed in a deterministic setting that does not take into account renewable energy production uncertainty, or day-ahead market profile uncertainty.

These previous studies highlight certain influences of temporal correlation rules but do not model both green and low-carbon hydrogen production. They also use deterministic models that are not able to integrate risk-averse behaviour of producers with respect to renewable production and spot price uncertainties.

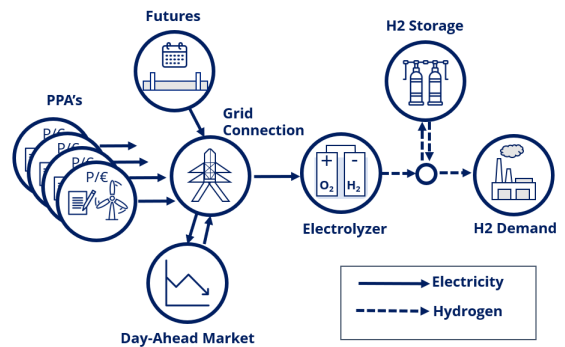


Fig. 1: H<sub>2</sub> production model, overview diagram.

### A. Contributions of this paper

The contributions of this papers are the following:

- A linear program model of a hydrogen producer that can be used for planning energy procurement and equipment sizing for a variety of hydrogen classification rules and subsidy levels. To the author’s knowledge, it is the first model proposed in the literature which is able to optimise multiple production alternatives (ie. green and low-carbon), and using different rules for eligibility of sources.
- A techno-economic analysis of the effects of different green hydrogen classification regulations and subsidies for a risk-averse producer’s micro-economic preferences. Renewable production and day-ahead price uncertainties are key risks considered by producers in project planning, and thus the stochastic model used in this study should provide a more realistic insight into producer preferences than deterministic models.

The structure of this paper is as follows: in Part III, an overview of the mathematical model is given, and several performance metrics are defined. In Part IV the 7 regulatory contexts are defined. In Part V the model is used to provide project planning decisions for each of these contexts, the results analysed, and their implications discussed. Part VI concludes and offers several perspectives on the results.

## III. METHODOLOGY

### A. Problem Statement

The aim of this study is to analyse the preferences of a green hydrogen producer contracted to a single consumer (offtaker), operating in a particular regulatory context. The aim is to minimise the expected hydrogen break-even sale price whilst also limiting the worst-case scenario sale price.

### B. Model Overview

The system shown in Figure 1 is modelled as a linear program. The offtaker’s hydrogen demand is supplied by an electrolyser and hydrogen storage tank. The electrolyser is modelled as a linear efficiency  $\eta^{ez}$ . Electricity is supplied to the electrolyser from the larger network, with access to a variety of sourcing options, including the day ahead market, a set of futures products  $\mathbb{Q}$ , and a set of renewable PPA options  $\mathbb{A}$  (see Table IV).

1) *Objective Function*: Investors in the energy industry are likely to be risk-averse (ie. placing a high importance on avoiding bad outcomes). As such, a risk-averse objective function is used as for [15], where operational costs are weighted between the expected value across all scenarios, and that of the worst-case (obtained using the CVAR [16]):

$$\min_{x,u} \underbrace{J^d(x,c,b)}_{\text{Design Cost}} + (1-\beta) \cdot \underbrace{E[J_s^o(x,u_s,w_s,g)]}_{\text{Operational Cost (all)}} + \beta \cdot \underbrace{CVAR_\alpha[J_s^o(x,u_s,w_s,g)]}_{\text{Operational Cost (Worst)}} \quad (1)$$

The first-stage "design" decisions  $x$  involve capacity installation (e.g., electrolyser, hydrogen storage, grid connection) and energy procurement (e.g., PPA commitments, electricity futures). These decisions incur design costs based on price parameters  $c$ , and network access power charges  $b$ . The second stage 'operational' decisions  $u_{s,h}$  determine asset dispatch for hour  $h$  over one year for scenario  $s$ , based on design decisions and scenario uncertainties  $w_{s,h}$ . Operational Costs for scenario  $s$  include green hydrogen subsidies  $J_s^r$ , net day-ahead (spot) market costs  $J_s^{da}$ , PPA contract costs  $J_s^{ppa}$ , non-served demand penalties  $J_s^{hd,curt}$ , and network access energy costs  $J_s^{nw}$ .

$$J_s^o = J_s^{da} + J_s^{ppa} + J_s^{hd,curt} + J_s^{nw} - J_s^r \quad (2)$$

Where  $J_s^r$  is dependent on the total amount of green-eligible hydrogen produced  $\Gamma_s$ , and the subsidy level  $G^{r-e}$  in €/MWh:

$$J_s^r = \Gamma_s \cdot G^{r-e} \quad (3)$$

2) *Parameters and Scenario Generation*: Scenario generation uses French spot prices for 10 years 2013-2022 [17] (with an average price of 70€/MWh), and renewable production data for geographic locations in France associated with the 9 PPA options for the same time period [18], [19]. The same 10 in-sample and 20 out-of-sample scenario sets are used for optimization and testing respectively of each regulatory context studied (see Section IV). Key parameters are given in Table III, and full modelling and scenario generation details are available in [15]. In this paper new constraints relating to green hydrogen classification rules and subsidies are used. They are described in the following sections.

3) *Green Hydrogen Temporal Accounting*: Green hydrogen classification is associated with the consumption of renewable power only (originating from the PPA's in this study). The calculation of the total volume of green-eligible hydrogen produced  $\Gamma_s$  depends on the temporal correlation used. **Annual** temporal correlation is implemented using the following two constraints:

$$\Gamma_s \leq \sum_{h=1}^H \left( \sum_{a \in \mathbb{A}} u_{s,h}^{ppa,out,a} \right) \cdot \eta^{ez} \quad (4)$$

$$\Gamma_s \leq \sum_{h=1}^H u_{s,h}^{ez,in} \cdot \eta^{ez} \quad (5)$$

$$\forall s \in [1..S].$$

For **monthly** temporal correlation, an additional set  $\mathbf{M}$  is used containing a set of the hours within each month. The green hydrogen produced for each month is denoted  $\gamma_{s,m}$ .

$$\gamma_{s,m} \leq \sum_{h \in m} \left( \sum_{a \in \mathbb{A}} u_{s,h}^{ppa,out,a} \right) \cdot \eta^{ez} \quad (6)$$

$$\gamma_{s,m} \leq \sum_{h \in m} u_{s,h}^{ez,in} \cdot \eta^{ez} \quad (7)$$

$$\forall s \in [1..S], m \in \mathbf{M}$$

where

$$\mathbf{M} \in \{[1..744], [755..1427], \dots [8016..8760]\}. \quad (8)$$

Thus the total for the year is found by:

$$\Gamma_s = \sum_{m \in \mathbf{M}} \gamma_{s,m} \quad (9)$$

Finally, for **hourly** temporal correlation,  $\gamma$  is instead indexed by hour ( $h$ ), and the constraints used are then:

$$\gamma_{s,h} \leq \left( \sum_{a \in \mathbb{A}} u_{s,h}^{ppa,out,a} \right) \cdot \eta^{ez} \quad (10)$$

$$\gamma_{s,h} \leq u_{s,h}^{ez,in} \cdot \eta^{ez} \quad (11)$$

$$\forall s \in [1..S], h \in [1..H]$$

and

$$\Gamma_s = \sum_{h=1}^H \gamma_{s,h} \quad (12)$$

### C. Performance Metrics

Three performance metrics are used to compare the results on the out-of-sample scenarios:

1) *Levelised Cost of Hydrogen (LCOH)*: The first performance metrics is LCOH, calculated as the break-even hydrogen sale price.

2) *Green Hydrogen Production Proportion*: This is total amount of hydrogen demand served as green hydrogen (as opposed to low carbon hydrogen), using the rules for the given context.

3) *Grid-Mix Exposure Factor*: This measure denotes the component of energy bought on the energy markets (spot or futures) in MWh per kilogram of H2 produced.

## IV. REGULATORY CONTEXTS STUDIED

A total of 7 regulatory contexts are studied, which are distinguished by the energy mix type of the local grid (the grid geographically correlated with the electrolyser), and temporal correlation used. In all 7 contexts, a 3€/kg green hydrogen subsidy level is used.

### A. High CO2 Local Grid

The first set of three contexts **1.A**, **1.M**, and **1.H** represent Annual, Monthly, and Hourly time-matching respectively in the case of a High CO2 grid. Given the unlikelihood of customer acceptance of high-carbon electrolytic hydrogen, it is assumed that 100% green-eligible hydrogen must be produced. In this study this means that 100% of electricity demand must be procured from time-correlated renewable PPA's. However, less strict time-matching rules (annual or monthly) allow some energy to be bought from the grid while still being eligible for 100% green accreditation. Context 1.A

corresponds to most Australian states, and many locations in the US prior to 2028. 1.M applies to many European countries before 2030. 1.H applies in the long term to these same European countries and many states of the US.

In order to ensure that only green-eligible hydrogen is produced for these high CO2 grid cases, the following constraint is added for these contexts only, which ensures that the total amount of green eligible hydrogen produced is equal to the total amount of hydrogen produced by the electrolyser across the year:

$$\Gamma_s \geq \sum_{h=1}^H u_{s,h}^{ez,in} \cdot \eta^{ez} \quad (13)$$

$$\forall s \in [1..S]$$

### B. Low CO2 Local Grid

The second set of three contexts **2.A**, **2.M**, and **2.H** represent again Annual, Monthly, and Hourly time-matching, but for a low-carbon local grid with high nuclear penetration, such as metropolitan France. In these contexts, hydrogen produced from market-sourced energy (day-ahead or futures) can be classified as low-carbon hydrogen. Low-carbon hydrogen is an acceptable alternative that may be produced without the purchasing of additional PPA's, however it does not receive the 3€/kg subsidy as for green-eligible hydrogen.

### C. Highly Renewable Local Grid

The final context **3.H** represents a low-carbon and highly renewable grid, such as Sweden's. In this case, low-carbon hydrogen can be produced from market-purchased electricity, and the average proportion of renewable energy in the grid mix  $G^{grp}$  can be claimed as renewable, contributing to green subsidies. Only hourly correlation is studied for this context. Equation 10 is modified to the following:

$$\gamma_{s,h} \leq \eta^{ez} \cdot \left\{ \sum_{a \in \mathbb{A}} u_{s,h}^{ppa,out,a} + G^{grp} \cdot \left( \sum_{q \in \mathbb{Q}} m_h^q \cdot x^{BaF-e,q} / H_q + u_{s,h}^{da,out} \right) \right\} \quad (14)$$

$$\forall s \in [1..S], h \in [1..H]$$

Energy bought on the (Baseload) futures market  $x^{BaF-e,q}$  is also derived from the general grid energy mix.  $m_h^q$  is the unit function that is 1 during the delivery period of futures product  $q$  and 0 otherwise.  $H_q$  is the delivery period duration of futures product  $q$ .  $G^{grp} = 80\%$  is used.

## V. RESULTS AND DISCUSSION

For each of the regulatory contexts of Section IV the model was solved to determine equipment capacity installation decisions (Table II), and the energy hedging decisions, shown in terms of hedging ratio in Plot 1 of Figure 2. The hedging ratio is calculated as the average amount of energy procured for in-sample scenarios as a proportion of the total electrical demand of the electrolyser for the year. Performance metrics (Section III-C) were calculated from out-of-sample testing.

Context	Local Grid Energy Mix	Temporal Correlation	Hydrogen Classifications
1.A	High CO2	Annual	Green only
1.M	High CO2	Monthly	Green only
1.H	High CO2	Hourly	Green only
2.A	Low CO2 (with Low RE)	Annual	Green Low Carbon
2.M	Low CO2 (with Low RE)	Monthly	Green Low Carbon
2.H	Low CO2 (with Low RE)	Hourly	Green Low Carbon
3.H	Low CO2 (80% RE)	Hourly	Green Low Carbon

TABLE I: Regulatory context definitions.

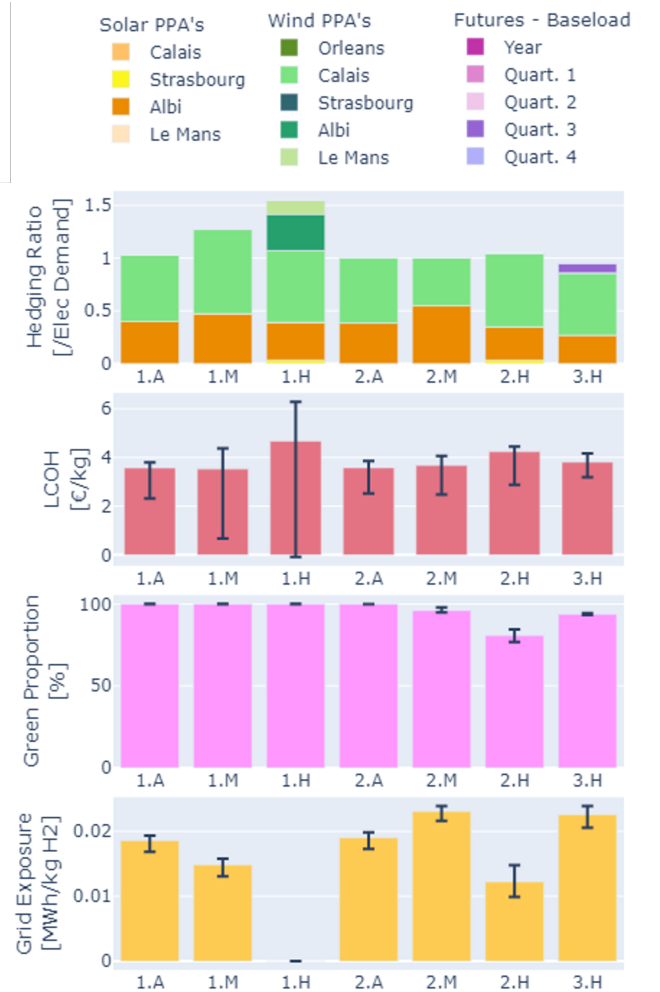


Fig. 2: Result plots from top to bottom. Bars represent average values, whiskers represent maximum and minimum scenario values: (1) energy hedging decisions, given by hedging ratio with respect to total electricity demand; (2) Levelised Cost of Hydrogen; (3) Green-eligible proportion of total hydrogen produced; and, (4) Grid-mix exposure factor, calculated as the quantity of market-purchased electricity per kilogram of final hydrogen demand.

### A. Equipment Sizing and Procurement Decisions

1) *High CO2 Local Grid contexts 1.A, 1.M, 1.H*: Equipment sizing is mostly consistent across the contexts studied, except for the strictest context 1.H (High CO2 grid with hourly time matching). For this case, the interdiction to use the day-ahead market for flexibility means that this additional flexibility must be obtained through increased asset flexibility. This increased CAPEX drives the higher average LCOH in this context.

With respect to procurement decisions, stricter temporal correlation rules necessitate an increasingly over-hedged electricity consumption, with monthly and hourly contexts 1.M and 1.H investing in higher average PPA volumes in order to manage the uncertainty of production. This results in a much greater variance in LCOH, as the final price becomes increasingly sensitive to the resale value of the surplus PPA energy. The strict 1.H context also requires investment in more expensive PPA options (both wind and solar) showing an increased value in obtaining diversified production uncertainties.

2) *Low CO2 Local Grid contexts 2.A, 2.M, 2.H*: For a Low CO2 local grid with low renewable penetration, modest increases in asset sizing are observed for stricter temporal correlation rules. However, unlike the High CO2 grid context, the hedging ratio stays steady at close to 1. For the stricter hourly correlation rules in context 2.H, increased diversity of PPA choice is again observed, with the addition of a more expensive solar PPA option.

3) *Highly Renewable Local Grid context 3.H*: For the highly renewable grid context 3.H, a small futures purchase for the 3rd quarter of the year is used. This reflects the improved attractiveness of hedging using standard futures products when 80% of market-purchased electricity can be counted as renewable. The smaller overall hedging ratio is likely due to the reduced volume uncertainty of futures hedging with respect to PPA hedging, and an increasing willingness to use the spot market.

### B. Temporal Correlation

Little difference is observed in LCOH performance between annual and monthly time-matching (in both the High CO2 grid and Low CO2 grid contexts). In all contexts, hourly time matching results in higher LCOH, especially for the High CO2 grid context 1.H.

For annual time-matching, the design decisions are identical for 1.A and 2.A. This suggests that a 3€/kg subsidy is large enough (and for annual time-matching, easy enough to obtain) to incentivize 100% green hydrogen classified production, even with the option of producing low-carbon hydrogen.

The larger grid-mix exposure factor for monthly time matching in 2.M with respect to 2.A is surprising, as we might expect the stricter rules to result in less energy bought from the market (as is the case for the High CO2 grid context). However, for 2.M the producer also produces slightly less green-eligible hydrogen overall. This indicates that the producer may opt to produce low-carbon hydrogen at a lower cost, avoiding the risk of over-hedging. This is supported when comparing 2.M with 1.M, where the only significant difference in planning decisions is increased hedging for 1.M,

Context	Electrolyser Capacity (MW)	H2 Storage Power (MW)	H2 Storage Energy (MWh)
1.A	4.7	3.9	24.8
1.M	4.7	3.9	24.8
1.H	6.0	5.2	113.6
2.A	4.6	3.9	24.8
2.M	4.7	3.9	26.7
2.H	4.8	3.8	35.6
3.H	4.7	3.8	25.6

TABLE II: Equipment capacity decisions.

which results in a much higher LCOH variance than that of 2.M.

### C. Grid Exposure and Carbon Intensity

The average grid carbon intensity of Germany was 400kgCO2/MWh in 2023 [20]. For the 1.M case (applicable in Germany up until 2030), an average of 0.0148 MWh of grid-mix energy is bought per kilo H2 produced, corresponding to an average carbon intensity of 5.9kgCO2/kgH2. This is significantly higher than the EU intended limit of 3.4 kgCO2/kg for RFNBO or low-carbon hydrogen.

In the case of NSW in Australia, the average grid carbon intensity was 545kgCO2/MWh for 2023 [20]. In this study for the applicable regulatory context 1.A, 0.0186 MWh of grid-mix energy is bought per kilo H2, corresponding to a hydrogen carbon intensity of approximately 10kgCO2/kgH2. This is more than 16x greater than the Australian Government's intended maximum carbon intensity of 0.6kgCO2/kgH2 for green-eligible hydrogen.

It can be concluded that hourly temporal correlation is necessary to ensure true 'greenness' of green hydrogen in high CO2 grids, though it will also increase costs. Both aspects must be acknowledged. The aim of green hydrogen is decarbonation, so visibility of its true impact on emissions is critical. However with the industry developing slowly, all measures that encourage investment by first movers should be considered. The European and US schemes offer a compromise: allowing less strict time-matching initially, moving to more accurate hourly matching later. In contrast, Australia's plan to use only annual matching in the long term locks in low visibility of green hydrogen's true decarbonation effect. This is particularly important in the context of hydrogen imports and exports, as stricter jurisdictions should consider carefully how they classify 'green' hydrogen imported from regions with looser time-matching rules.

## VI. CONCLUSION

This study analysed the effect of different green hydrogen classification rules on equipment sizing and energy hedging preferences for a single electrolytic hydrogen project proposition. As access to subsidy schemes is directly dependent on electricity sourcing methods, changes in classification rules can result in large differences in optimal energy procurement decisions and asset sizing decisions.

It was found that increasing strictness of temporal correlation generally results in greater hedging ratios and use of more diverse PPA portfolios. However in the case where the producer is allowed to produce low-carbon hydrogen, this

effect is much more nuanced, as the producer opts instead to forgo a certain amount of the green subsidy in order to avoid the risk involved in over-hedging.

Hourly time matching results in a higher LCOH. The difference in average LCOH between annual and monthly time matching is small, however in high CO<sub>2</sub> grid locations the need to over-hedge renewable production for monthly and hourly time matching results in a high variance in LCOH due to an increased sensitivity to energy resale value.

Less-strict time-matching can result in the produced hydrogen being technically classified as 100% green yet resulting in a significantly higher emissions intensity than intended. Jurisdictions with accurate hourly temporal correlation should be wary of importations of supposedly 'green' hydrogen produced in jurisdictions with looser time-matching rules.

This work could be furthered by investigating the sensitivity of the results to the subsidy level, and/or with different carbon intensity categories as for the US 45V program.

Finally, the treatment of carbon emissions factors in this study is based on yearly averages, and does not consider a decarbonation impact of excess PPA energy resold to the grid. An improvement could be made by considering average and/or marginal emissions factors on an hourly basis.

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Model Parameters					
Electrolyser + Compressor	Combined CAPEX	1.7 M	€ /MW (Elec)		
	Combined Efficiency	56 %	MWh (H2) / MWh (Elec)		
	Lifetime	13	Years		
H2 Storage	CAPEX (Energy)	75k	€ /MWh		
	CAPEX (Power)	50k	€ /MW		
	Power/Energy Efficiency	100 %			
	Usable Capacity	100 %			
	Initial SOC	50 %			
	Lifetime	25	Years		
Network Connection	CAPEX	75k	€ /MW		
	Lifetime	25	Years		
Project (Global Parameters)	Discount Rate	5 %			
	Lifetime	25	Years		

TABLE III: Model common parameters.

	Location	CF Min	CF Mean	CF Max	Price (€/MWh)
Solar PV	Le Mans	14.5 %	15.0 %	16.2 %	71
	Calais	14.2 %	14.8 %	15.4 %	72
	Strasbourg	14.7 %	15.3 %	16.2 %	68
	Albi	16.0 %	16.8 %	17.5 %	66
Wind	Orleans	25.5 %	27.7 %	31.4 %	70
	Le Mans	27.1 %	29.3 %	32.7 %	69
	Calais	40.9 %	42.7 %	46.5 %	65
	Strasbourg	15.1 %	16.9 %	19.5 %	80
	Albi	24.6 %	25.8 %	26.5 %	78

TABLE IV: PPA capacity factors (CF) and chosen prices.

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