The economic viability of grid-connected power-to-hydrogen conversion - quantifying short- and long-term determinants

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Abstract

Hydrogen is viewed as a promising supplement in energy systems with high penetration rates of renewable energy (RE) generation. It embodies characteristics that complement well the properties of the dominant secondary energy carrier electricity, e.g., its suitability for long-term storage and long-distance transportation. As conversion technology between the two secondary energy carriers, hydrogen and electricity, particularly grid-connected electrolysers, have a role to play. Their economic viability depends on the design of these resource markets, particularly electricity markets. The paper presents a model framework including a mixed-integer linear program and a Markov chain Monte Carlo simulation for stochastic electricity market prices to assess a grid-connected electrolyser's viability. As crucial determinants of the electrolyser's short- and long-term viability, the willingness-to-pay (WtP) for green hydrogen and a criterion for simultaneity between hydrogen production and RE generation are the subjects of the quantitative analysis. The results show that the contribution margin for a WtP of 3 €/kg and a required simultaneity of 1 hour is insufficient to finance the electrolyser investment leaving a median financing gap of 3.6 €/kg. Increasing the WtP and lowering the simultaneity requirement contribute to closing the financing gap. Regulations aiming at the interface between the secondary energy carriers hydrogen and electricity must consider the trade-off between total cost per produced hydrogen, full load hours, and the renewable characteristic of the hydrogen.

Keywords: hydrogen, power-to-gas, renewable energy support, optimisation

JEL classification: C61, L51, M20, Q41, Q42, Q48.

1. Introduction

In the course of decarbonisation, renewable primary energy carriers substitute fossil primary energy carriers (Smil, 2017). So far, this substitution process has mainly been performed within the generation of

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the secondary energy carrier electricity. Prominent examples of energy policy instruments like carbon pricing in the form of the European Emission Trading System (EU ETS) or subsidising renewable energies (RE) in the form of the German Renewable Energy Act (Renewable Energy Act, 2021) indicate this prioritisation. However, the integration of renewable primary energy carriers has been realised in a system relying on multiple energy carriers. In the next phase of the energy system transformation, the remaining fossil energy carriers, particularly hydrocarbons such as natural gas and oil, must be replaced. This transformation can be achieved by electrification of natural gas and oil applications, e.g., through heat pumps or electric vehicles, or by substituting hydrocarbons with climate-neutral gases like hydrogen or synthetic natural gas. While the former option seems like the logical extrapolation of current policies, the latter option may maintain benefits multiple energy carriers contribute to a robust energy system. These benefits may be valuable, in case the electricity system does not meet the expectations associated with an energy system that relies on a single secondary energy carrier (Koirala et al., 2021).

In anticipation of the challenges of pure electrification, hydrogen has recently again been promoted as a promising supplement to the RE carrier mix (Ball and Wietschel, 2009; International Energy Agency, 2019; Crabtree et al., 2004). It embodies characteristics that complement well the properties of electricity. First, with its high gravimetric energy density (Mazloomi and Gomes, 2012), hydrogen is suitable for long-term storage and long-distance transportation (Speirs et al., 2018). Both applications are typically not explored by electrical technologies. Second, hydrogen as an additional energy carrier relieves the electricity infrastructure. Incorporating parallel infrastructure could increase the overall robustness of the energy system, relaxing the requirements on transforming the electricity infrastructure, e.g., using the existing gas infrastructure. Third, hydrogen shows higher economic efficiency than electricity in some final energy conversion processes, e.g., in heavy road transport, in high-temperature industry applications (Dodds et al., 2015; Parra et al., 2019), and steel production. Although hydrogen is often discussed as the successor of fossil fuels, it must be noted that it is no primary energy resource. Thus, like electricity, it will rely on converting the primary energy resources wind and solar. This dependence poses the question of how electricity and hydrogen systems should be integrated, i.e. how to orchestrate the utilisation of both secondary energy carriers (Mancarella et al., 2016).

Crucial elements in integrating these two systems are energy conversion technologies like Power-to-Gas (PtG) plants. In the current discussion, the role of PtG plants is of interest since additional capacities are needed for the ramp-up of hydrogen supply (Lambert and Schulte, 2021). Four options exist for the integration of PtG plants in the electricity system. First, PtG plants can be located directly at the RE power plant so that they are supplied by a "dedicated RE plant" (Ferrero et al., 2016). Second, PtG plants could utilise grid-curtailed power (Larscheid et al., 2018). Third, PtG plants could utilise economic-curtailed power (Baumann et al., 2013).Last, PtG plants could be integrated as normal electricity consumers purchasing electricity on the wholesale market (Nguyen and Crow, 2016). The first option favours hydrogen as a secondary energy carrier, as primary energy is directly converted to hydrogen without being fed into the electricity system. The second and third options favour electricity as a secondary energy carrier since hydrogen is only used as a peaking energy carrier when the electricity infrastructure is congested or the power balance between supply and demand cannot be maintained. Therefore, this paper focuses on the fourth option as neutral integration of both systems and the most common case of PtG operation in the short-term. A better understanding of this conversion process's short- and long-term economic determinants may contribute to integrating PtG plants into today's energy systems.

This paper evaluates the determinants of an electrolyser's short- and long-term viability in a transitioning energy system. We highlight the conversion between two secondary energy carriers as defining property of an electrolyser and analyse the implications of this role for the viability of such an asset. We assess four aspects of this viability: the general potential for cross-commodity arbitrage, the translation of associated green characteristic from electricity to hydrogen and its dependence on the regulatory definition, the associated risk regarding the intermittent nature of RE generation, and the translation of associated carbon emissions, which occur as long as the electricity supply still contains fossil-fired power plants. The analysis mainly accounts for the price variation on day-ahead and intraday markets in the electricity system due to volatile RE generation, the short-term and long-term costs of the electrolyser, and the associated CO_2 emissions in a transitioning electricity system.

We develop a model framework including a mixed-integer-linear program to determine the optimal operation of an electrolyser, a parametrical representation of day-ahead and intraday markets, and a Monte Carlo simulation to generate random wind generation. We apply the framework to an electrolyser located in Germany and vary the electricity prices for the year 2019. We draw random wind generation realisations for this case and evaluate the distribution of the contribution margin. We vary the hydrogen price and the regulatory setting, expressed by the obliged simultaneity of RE and hydrogen generation, to evaluate their impact on the viability of the electrolyser. We discuss our results concerning the impacts on the operation of an electrolyser, the investment into an electrolyser, and their implications for possible subsidies to enforce a market ramp-up.

The results stress the importance of the Willingness-to-Pay (WtP) for green hydrogen. The WtP determines both the price effect and the quantity effect on the absolute contribution margin since the electrolyser runs in more hours under a high WtP also utilising hours with higher electricity prices. Both a higher WtP and low requirements to the simultaneity between RE generation and hydrogen production increase the contribution margin of the electrolyser while reducing the risk resulting from the volatile RE generation. In the long-term, including the investment costs, a financing gap exists for all randomly created realisations. If policymakers contribute to reducing the financing gap by increasing the WtP or lowering the simultaneity requirements, they need to account for the volatility of the financing gap to avoid over- and under-investment.

To the best of our knowledge, the paper at hand is the first to evaluate the dependence of an electrolyser's short- and long-term viability on the simultaneity between RE generation and hydrogen production and the risk of RE generation. The remainder of the paper is structured as follows: Section 2.1 describes the state of the literature on the economics of electricity-to-hydrogen conversion. Section 3 presents the model framework and the numerical assumptions for the case study, and section 4 shows the results. In section 5, we discuss the implications of our findings. We conclude our paper in section 6.

2. The economics of power-to-hydrogen conversion

The economics of power-to-hydrogen conversion have been subject to broad research. We first review this literature in Section 2.1 and use the insights to narrow down the system considered within our analysis in 2.2.

2.1. Related work

A PtG plant converts electricity into hydrogen, benefiting from cross-commodity trading between these two secondary energy carriers (Baumann et al., 2013). The economic viability strongly depends on the conversion efficiency and the market prices on the input and output side (Glenk and Reichelstein, 2019). On the input side, electricity prices are the most crucial cost factor, which is increasingly characterised by the volatility of RE generation. Electricity procurement can take different forms, significantly impacting the PtG business case: (i) The PtG plant is co-located and physically connected with a RE generation plant. The production of hydrogen is profitable when hydrogen sales yield higher revenues than selling electricity on the market, assuming that the RE generator is connected to the grid (Glenk and Reichelstein, 2019). (ii) Further, the PtG plant can be both connected to the public grid and co-located with a RE generator, forming a vertically integrated portfolio that can be optimised against volatile electricity prices (Glenk and Reichelstein, 2020). (iii) A grid-connected PtG plant optimised against electricity market prices to maximise hydrogen production at a minimal cost. Several sequential markets are available in liberalised electricity markets, e.g., day-ahead, intraday, and balancing markets. With their fast ramping capabilities, PtG plants may be particular suited for short-term markets like the intraday or balancing market. On the latter, they can procure grid services, such as primary (Samani et al., 2020), secondary (Kopp et al., 2017), or tertiary reserve power (Baumann et al., 2013), or reduce system imbalances by using RE curtailed power in the case of grid congestion (Larscheid et al., 2018). Each electricity procurement strategy yields individual economic and operational constraints for the PtG dispatch, such as capacity factors, electricity supply cost, or availability of electricity from RE. Furthermore, the electricity supply has an impact on the *renewable* characteristic of hydrogen, which might be relevant for downstream actors, e.g., consumers who replace fossil energy with renewable gases.

Currently, hydrogen can either be sold to industrial consumers at (nearly) fixed price rates (Luck et al., 2017) or sold as a close substitute to natural gas (Haeseldonckx and D'haeseleer, 2007). Hence, the WtP for natural gas or hydrogen affects the plant's profitability on the output side. The WtP for hydrogen significantly influences the viability of the PtG plant (Larscheid et al., 2018), though also by-products like oxygen (Kato et al., 2005) and heat (Parra et al., 2017) can improve the investment's profitability. Since hydrogen is still mainly used as a chemical input in industrial processes, there are only vague estimates on its possible equilibrium prices at a prospective hydrogen market. Thus, literature either considers inelastic demand in single use cases for the industry, mobility, or heating sector or derives hydrogen prices from conventional production or derived products like synthetic methane (Fragiacomo and Genovese, 2020; Matute et al., 2019; Breyer et al., 2015; Glenk and Reichelstein, 2019; Baumann et al., 2013).

Combinations of these input-output options form different business cases for PtG plants assessed by previous work. For example, Breyer et al. (2015) perform a profit-and-loss calculation for a PtG plant producing hydrogen and synthetic methane in a pulp mill process. They consider the revenue streams of all perceivable products and services of the plant, i.e. hydrogen/ synthetic methane production, grid services, utilisation of excessive CO_2 (when hydrogen is converted to methane), oxygen production, and usage of waste heat from the electrolysis plant. Profits and losses are calculated for two different case studies and show that all revenue streams must be used to realise a profitable business case for the PtG plant. Glenk and Reichelstein (2019) considers exclusively dedicated electricity supply from RE to feed the PtG plant for hydrogen production. This power supply option requires a direct physical connection between the RES plant and the hydrogen-producing entity, thus, forcing the PtG plant to be closely located to the power source. Fragiacomo and Genovese (2020) allow the PtG plant to receive electricity from local RE plants and the public grid while considering hydrogen feed-in into the gas grid and hydrogen supply for the transport sector. They find that the business case is most promising for combining the PtG plant with a wind farm compared to combinations with geothermal or photovoltaic electricity generation. Glenk and Reichelstein (2020) present an analysis of a grid- and RE-connected PtG plant. Power production from the RE source can either be sold on the electricity market or used to produce hydrogen. Hence, the vertically integrated system creates operational opportunities, resulting in increased net present values of the integrated system compared to stand-alone systems. The level of operational gains strongly depends on the optimal sizing of the RES and PtG plant. Brändle et al. (2021) determine and compare global hydrogen production cost of different RE technologies with low carbon hydrogen from natural gas reforming with carbon capture and storage or pyrolysis. PtG plants are assumed to be connected to RE plants only. Darras et al. (2015) optimise the ratio of a grid-connected photovoltaics (PV)/hydrogen-system with a techno-economic optimisation, where electricity from a PV plant can either be injected into the electricity grid or fed into a PtG plant. The system is optimised to supply an exogenous power demand. The economic viability strongly depends on the PV/PtG-capacity ratio and the feed-in premium of PV-produced electricity. Carr et al. (2014) present a case study where excess wind power is converted to hydrogen to supply demand from the transportation sector. Larscheid et al. (2018) explore two business cases of a grid-connected PtG plant: (i) the optimal operation based on electricity prices to maximise revenue from hydrogen production and cross-commodity trade, and (ii) using the PtG plant for grid congestion management. The rationale of the first business case is that PtG plants have fast ramping capabilities and benefit from electricity price fluctuations. The output price of hydrogen is less volatile than the input price of electricity. Hence, optimising against the electricity price offers potential for cross-commodity trade gains. They find that the PtG can be viable for applications in the transport sector while it is less competitive in the industry and heating sector. However, the second business case can contribute to profitability.

While the assessments of PtG use cases found in literature contribute to a complete picture of the value of PtG in the energy system, the description of the conversion value of PtG remains selective. In most cases, the analyses rely on point observations of a PtG plant's operation concerning the considered input and output combinations. We contribute to this stream of literature by developing a scalable methodology that integrates sequential electricity markets by accounting for varying RE feed-in and is adjustable to varying hydrogen benchmarks on the output side. We distinguish in particular the short- and long-term viability and evaluate the underlying effects.

2.2. System layout

In light of the literature, we focus our analysis on an electricity grid-connected electrolyser. The system under consideration consists of this grid-connected electrolyser, which uses electricity withdrawn from the grid to produce hydrogen sold at an exogenous hydrogen price. [1] As we are particularly interested in the production of green hydrogen produced with RE, we define our system for its interaction with grid-connected RE plants. Four system layouts are possible from the premise that electrolyser and RE plants are connected through the electricity grid. They depend on the level of *simultaneity* of production between electrolyser and RE plant and the level of *dedication* between electrolyser and RE plant. The former describes to which extent the electrolyser receives electricity in the same instant as the RE plant feeds in electricity. The latter describes to which extent the total electricity consumption of the electrolyser balances with the total generation of the RE plant. Figure 1 illustrates the four options of RE and electrolyser interaction: *market-integrated system*, *RE-integrated system*, *balanced dedicated system*, and *grid-connected dedicated system*.

The *grid-connected dedicated system*, in which hydrogen and RE production are entirely aligned, and the electrolyser is exclusively dedicated to the RE plant, would be equal with the case of a dedicated RE-electrolyser system without electricity grid connection. The only difference to the dedicated integrated systems would be that the electrolyser and RE plant are connected via the electricity grid, relaxing the

[1] We abstract from costs for hydrogen transportation, distribution, and storage, as well as from revenues of by-products, e.g., heat or oxygen, and costs for water supply.

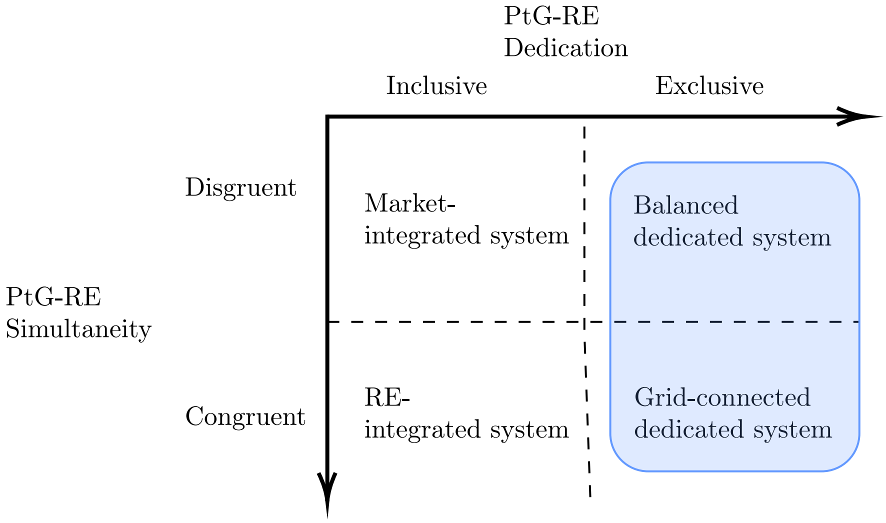

Figure 1: Categorisation of electrolyser and RE interaction for a grid-connected electrolyser.

constraints on the electrolyser location. The opposite case would be an utterly *market-integrated system*, in which the electrolyser's electricity consumption could be disgruent with the RE electricity generation, and the electrolyser could also consume electricity beyond the total production of the RE plant. This case is an electrolyser buying electricity on the wholesale market as a typical electricity consumer. Here, however, the green characteristic and the associated CO_2 emissions would be more challenging to track. The definition of green hydrogen becomes less evident than for the dedicated system.

For our analysis, particularly the cases in between these two edges are of interest. Starting from the *grid-connected dedicated system* and relaxing the dedication requirement, the electrolyser would still operate simultaneously with the PtG generation in the *RE-integrated system* but could consume more electricity than the RE plant generated. Thus, the electrolyser could rely on a portfolio of RE plants to optimise its full load hours (FLH), maintaining simultaneity with each of them. Relaxing the simultaneity requirement instead would result in a *balanced dedicated system*, in which the total production of the RE system is still binding for an electrolyser, while its consumption may be disgruent with the RE generation. Our analysis chooses this layout as it allows us to access the impact of simultaneity relaxation without loss of generality. Applying the methodology to the portfolio layout may be an additional contribution but is beyond the scope of this paper.

We consider an exclusive dedication between the electrolyser and the RE plant. The power is purchased from electricity spot markets, i.e., day-ahead and intraday market. The electrolyser is obliged to balance the power consumption with the power generation of a RE plant. Power production and consumption must be balanced within a defined time interval, i.e. the *simultaneity* of RE and hydrogen production. Consequently, if the simultaneity is defined accordingly, the electrolyser may consume more electricity than produced by the RE generator in some periods and in others less. It is assumed that this electricity is delivered by the grid and originates from various power sources, which are not further defined.

The simultaneity aims at ensuring a low-carbon intensity of hydrogen through balancing RE and hydrogen production. However, the electrolyser physically consumes electricity withdrawn from the grid and each positive deviation in the hydrogen production profile from the RE generation profile results in additional electricity demand, which other electricity producers must cover. Depending on the marginal power plant in the electricity system, this can lead to additional CO_2 emissions, as the marginal unit is required to increase electricity production to supply the electrolyser's demand.

3. Methodology

We aim to evaluate how the definition of the intersection between electricity and hydrogen systems affects an electrolyser's cross-commodity arbitrage potential in a transitioning energy system. For this purpose, we choose a methodology that captures a realistic representation of an electrolyser's operation, the volatility of a RE integrated electricity system, and appropriate metrics to assess the cross-commodity potential and the associated CO_2 emissions. Figure 2 summarises these key components of our methodological approach.

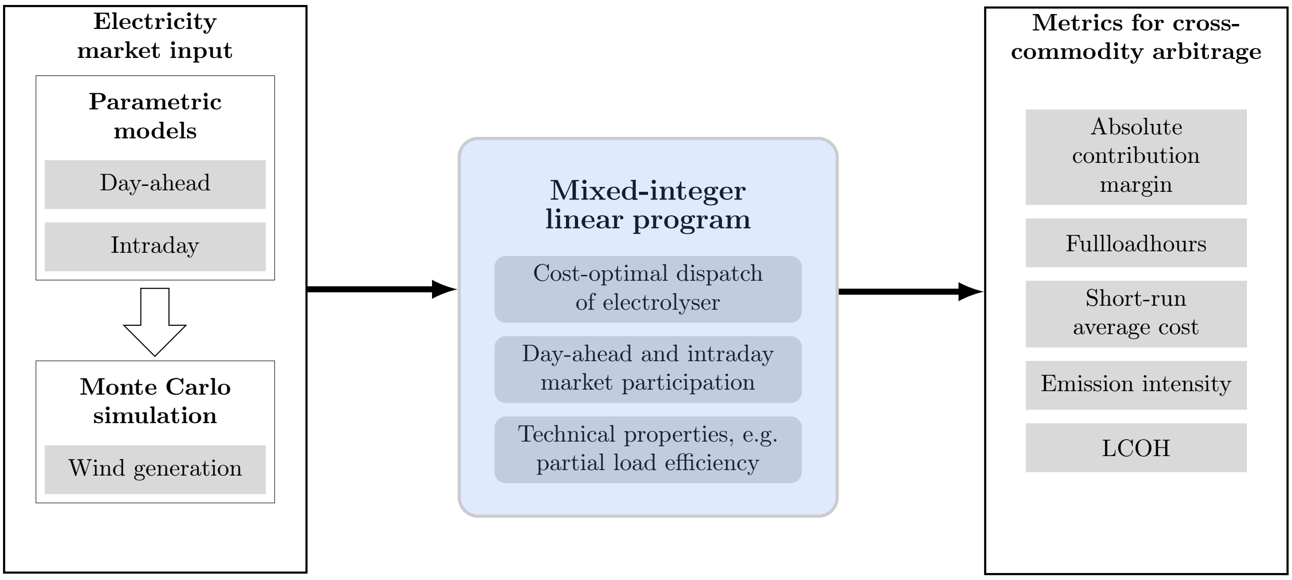

Figure 2: Methodological approach consisting of a mixed-integer linear program, stochastic price timeseries generation, and metrics for cross-commodity arbitrage

To estimate the optimal short-term viability of the electrolyser, we develop a techno-economic mixed-integer linear program, which simulates the cost-optimal dispatch of an electrolyser in a predefined system layout. According to the system layout, we design a case study with assumptions on techno-economic characteristics. The dispatch is optimised for exogenous wind generation and corresponding electricity prices. Two parametric models for day-ahead and intraday electricity markets capture the relation between wind generation realisations and electricity prices. A Monte Carlo simulation of synthetic wind generation realisations captures the risk resulting from uncertain wind generation. Finally, we evaluate our case studies with metrics for the viability and CO_2 intensity of the corresponding hydrogen production for the short-term cross-commodity arbitrage potential of the considered system.

3.1. Mixed-integer linear program of electrolyser operation

The economic viability of an electrolyser depends on its variable cost, fixed costs, and revenues. In the short-term, the cost-optimal dispatch of the electrolyser requires that revenues are equal or higher than the associated costs of the plant's operation. These decisions are modelled in the economic dispatch model, which simulates the operation of an electrolyser under a temporal resolution of 15 minutes. The plant must also cover operational fixed and investment costs to generate a profitable business case in the long-term. However, this is not considered in the short-term dispatch decision and, therefore, addressed in an ex-post analysis.

The economic dispatch model is formulated as a mixed-integer linear program (MILP). The objective function in equation (1)) maximises the profit over all simulated time periods $t \in T$ from revenues R_t of hydrogen production and costs C_t of electricity supply.

$$\max \quad \textit{Contribution margin} = \sum_{t}^{T} R_t - C_t \tag{1}$$

The revenue is calculated in (2) with an exogenous constant hydrogen price p^{H2} and the output of the plant, which depends on the load in period t and an input-output function f which converts electric input in MW into hydrogen output in kg considering a conversion efficiency. The total output of the plant depends on its total load L. The binary variable B determines whether the plant is switched on ($B = 1$) or off ($B = 0$). The constant δ ensures the correct time scale.

$$R_t = f(L_t, B_t) * \delta * p^{H2} \qquad \forall \ t \tag{2}$$

Equation (3) determines the variable cost of the electrolyser. In each period t, the plant's load L purchased on power market m is dispatched, whereby the set of markets M includes the day-ahead and intraday markets. The costs C are then calculated by multiplying the load with the corresponding electricity price p on the market and the fixed electricity surcharges α.

$$C_t = \sum_{m}^{M} L_{t,m} * (p_{t,m} + \alpha) * \delta^t \qquad \forall \ t \tag{3}$$

Its rated nominal capacity cap in MW_{el} limits the total load of the electrolyser (equation (4)).

$$\sum_{m} L_{t,m} \leq cap \qquad \forall \;\; t \tag{4}$$

The minimal load constraint (5) restricts the operating range of the electrolyser. The minimal load is expressed as a share $\beta \in (0, 1)$ of the nominal capacity cap.

$$\sum_{m} L_{t,m} \geq B_t * \beta * cap \qquad \forall \;\; t \tag{5}$$

The electrolyser is assumed to be subject to a simultaneity of RE and hydrogen production. This simultaneity of power and hydrogen production essentially depends on a fixed time factor $\gamma \in T$, which defines the time interval in which RE generation and the electrolyser's electricity consumption must be balanced. Hence, a time factor of $\gamma = 1$ obliges the electrolyser to consume the maximum power production in the same period. If $\gamma > 1$, the electrolyser can virtually shift the RE production from one period to another. As the electrolyser is connected to the power grid, there is no restriction of power supply. The following equations operationalise the balancing of RE generation and hydrogen production. The sum of the total load L of one period t and all subsequent periods within the simultaneity factor γ must be equal or less than than the RE production in the same period. The RE production is determined by the relative RE output re multiplied by the electrolyser capacity cap and the RE scaling factor σ, which expresses the capacity ratio of RE and electrolyser. For the first periods ($t \leq \gamma$), the equation (6) is modified such that the latest period valid for balancing equals 1. This simultaneity constraint implies that a virtual RE power storage is generated during the electrolyser's operation, where RE power certificates are stored with a temporal validity of γ periods.

$$\sum_{m} L_{t,m} + \sum_{j=(t-\gamma-1)}^{t-1} \sum_{m} L_{j,m} \leq \sum_{j=t-\gamma+1}^{t} re_j * \sigma * cap \qquad \forall \;\; \gamma + 1 \leq t \leq T \tag{6}$$

While the model formulation simplifies some technical characteristics and does not consider all the electrolyser's business opportunities, it can solve the optimisation problem in very short computation time. The low computational time allows solving the deterministic model for several scenario values to follow a stochastic approach.

3.2. Synthetic electricity price time series

In a RE system, hydrogen production would rely, through a power system, on the primary energy carriers, wind and solar. Therefore, we emphasise the role of the electricity system in the value generation of an electrolyser. The availability of these resources is intermittent, observable in electricity systems with high penetration of wind and solar generation. Since intermittency will remain a crucial determinant of a RE system, we account for its impact on the electrolyser's value. Beyond analysing point observations based on a single weather realisation, we capture the risk-profile originating from the weather-dependency of renewable generation by performing two steps. First, we parameterise two linear models, one for the relation between RE generation forecasts and the day-ahead electricity prices and one for the relation between the intraday prices, day-ahead prices, and forecast errors. Second, we generate synthetic renewable generation time-series with a Monte Carlo simulation as inputs for the independent variables in our linear models.

The first linear model captures the link between day-ahead electricity prices p_t^{DA} as the dependent variable and the residual load q_t^{res} as an independent variable. Equation (7) shows the corresponding model formulation (Burger et al., 2003). Note that we take the forecast residual load as an independent variable as it describes the available information at the day-ahead auction (Elberg and Hagspiel, 2015). We choose a third-degree polynomial so that it captures the non-linear relation between day-ahead prices and residual load (Ehrlich et al., 2015). The captured functional relation is not a pure estimate of the merit order but also includes the demand-side price elasticity (Elberg and Hagspiel, 2015) implicitly. Additionally, ramp-up constraints, as well as scarcity situations, are addressed by the polynomial function. We fit one function per month so that the final model accounts for seasonal effects, e.g., wind generation, load, and resource prices.

$$p_t^{DA} = \epsilon_0 + \epsilon_1 q_t^{res} + \epsilon_2 (q_t^{res})^2 + \epsilon_3 (q_t^{res})^3 \tag{7}$$

The second polynomial model describes the relation between the intraday price p_t^{ID} as the dependent variable, and the day-ahead price p_t^{DA} and the forecast error FE_t^2 as independent variables in Equation (8). As we vary the wind generation, we model only the impact of forecast errors and day-ahead prices on the intraday price and let other influences remain unexplained (Hagemann, 2013). We use a second-degree polynomial model of the forecast error to account for the non-linear relation (Kulakov and Ziel, 2021; Narajewski and Ziel, 2020). Thus, our functional relation implicitly captures impact factors intraday price like scarcity situations and ramp-up constraints (Pape et al., 2016).

$$p_t^{ID} = \zeta_0 + \zeta_1 p_t^{DA} + \zeta_2 FE_t + \zeta_3 FE_t^2 \tag{8}$$

The parametric models capture the functional relation between wind generation, forecast errors, and electricity market prices. Following Papaefthymiou and Klockl (2008), we draw random wind generation and forecast time series. The creation of the Markov chain and the Monte Carlo simulation are explained in Appendix Appendix A.2. With these time series and the parametric models, we compute synthetic electricity price time series.

3.3. Evaluation metrics

The results are analysed for the short-run and the long-run profitability of the electrolyser. The short-run results only consider variable hydrogen production costs and exclude fixed cost and capital cost. The long-run results also include discounting the capital investment as well as the fixed cost of operation. The short-run results are highlighted with the following four metrics.

First, the electrolyser's annual contribution margin is evaluated, which is defined as the sum of hourly cost minus hourly revenues (see eq. 1). The contribution margin is greater or equal to zero. Otherwise, the electrolyser would not be dispatched. Second, we calculate the short-run average cost of operation. They are defined as the ratio of the sum of variable cost and total production volume within one year: $VC = \frac{\sum_t VC_t}{\sum_t Q_t}$. Third, FLH for one year are determined: $FLH = \frac{Q}{Cap}$ (de Groot et al., 2017). Fourth, the CO_2 emission intensity of hydrogen is determined. Hydrogen production with electricity itself does not create CO_2 emissions. However, depending on the emission factor of electricity, the indirect carbon emissions of grid-connected electrolysers can be larger than zero, whereby either marginal or average emission factors can be used. The drawback of average grid emission factors is their high inaccuracy due to a high variation in actual emission factors of power supply. Further, they neglect the merit-order principle of power plant dispatch, as in theory, the marginal power plant is the first to increase production when additional load is occurring in the system, therefore setting the marginal emission factor (Siler-Evans et al., 2012). An exact calculation of marginal emission factors and consequently of specific CO_2 emissions of hydrogen require time-consuming electricity market simulations (Stöckl et al., 2021; Braeuer et al., 2020), which are not compatible with our stochastic Monte Carlo approach. This is why we approximate the emission factor for two different cases to estimate the emission intensity of hydrogen.

We assume that a simultaneity of a quarter-hour, which is the lowest temporal entity of electricity balancing purposes in the EU, has an emission factor of 0 $gCO_2/kgHCO_2$, thus represents a perfect balancing of RE and hydrogen production[2]. Each (positive) deviation of the quarter-hourly hydrogen production from the RE generation consequently leads to additional electricity demand not supplied by the RE generator, hence, increased power production of the marginal power plant. The hydrogen emission intensity is calculated by dividing the total absolute CO_2 emissions (in kg) by the total absolute quantity of hydrogen produced (in kg). In contrast, the CO_2 emissions are determined by multiplying the electricity emission factor with the absolute (positive) deviation of electricity consumption from the RE production (in MWh). We apply the following emission factors of electricity:

- Marginal emissions factor (MEF): The marginal emission factor equals the specific emission factor of the marginal power plant, which sets the market price based on its marginal cost (Fleschutz et al., 2021). Hence, the marginal emission factor is determined by comparing the hourly day-ahead price and the marginal cost of different power plants.

- Yearly average emission factor (YAEF): The yearly average grid emission factor, defined as the total emissions of the power sector divided by total electricity production.

[2]While even in the case of quarter-hourly simultaneity the actual emissions induced by the electrolyser might be higher, the assumptions serves to enable comparability with higher simultaneity indices.

The long-run viability of the electrolyser further includes fixed cost, i.e., fixed operative and maintenance costs, and the annuity of capital expenditures (CAPEX). For the electrolyser to become profitable, the aggregated contribution margin must be equal to or higher to cover the fixed costs. Otherwise, the investment is not profitable. Thus, we first compare the contribution margin with the total fixed cost. Second, we use the metric levelised cost of hydrogen (LCOH) to show the overall long-run hydrogen supply cost. Appendix A.3 shows the corresponding formulas.

3.4. Case study design

We simulate the proposed model with historical data from the German electricity market and exemplary inputs for the electrolyser. Electricity market data include day-ahead and intraday spot prices of the German electricity market zone from 2015 until 2019.[3] Forecast and realised electricity demand and generation time series are withdrawn from the data publication platform of the German federal grid agency (German Federal Grid Agency (Bundesnetzagentur), 2021). Electricity demand, generation, forecast and intraday price data is available in quarter-hourly resolution, whereby day-ahead prices are given in hourly resolution. Accordingly, we take electricity generation data for the years from 2015-2019 [4] (German Federal Grid Agency (Bundesnetzagentur), 2021). The simulation is run in quarter-hourly resolution for one year and 1000 samples of wind generation and derived electricity prices. The resulting parametric models for the electricity prices are shown in Appendix A.1, and A.11 and A.12 illustrate the synthetic electricity price time series.

The parameterisation of the electrolyser is based on literature data and summarised in table 3. The assumed parameters can only represent an exemplary electrolyser. In practice, the range of technical and economic characteristics is extensive and depends on multiple factors. Various review articles and studies published data on techno-economic electrolyser characteristics. Consequently, the simulation results strongly depend on the parameterisation of the electrolyser. Based on current German regulation, we assume electricity price surcharges of 2.39 €/MWh [5].

The exogenous hydrogen price is set to 3 €/kg in the base case and varied in a subsequent simulation (see chapter 4). Currently, hydrogen is not traded on transparent and liquid markets. Instead, over-the-counter trades and bilateral contracts between producers and consumers arrange volumes and prices. The assumed hydrogen price tries to reflect the WtP for green hydrogen.

A reference list mapping MEF with electricity prices is derived from Fleschutz et al. (2021), covering the German power market. A day-ahead price less than 35.5 EUR/MWh is below the lowest marginal cost of conventional power plants in the reference list. Hence, the marginal emission factor is assumed to be 0

[3]The year 2020 was excluded due to its low comparability with other years caused by the covid-19 pandemic.

[4]wind generation data, forecast error data

[5]The surcharges consist of 1.54 €/MWh electricity tax and 0.85 €/MWh other surcharges

gCO_2/kWh. As average grid mix emission factor of Germany we assume 408 gCO_2/kWh (Umweltbundesamt, 2021).

Parameter	Value	Unit
Production capacity	1	MW_{el}
Ramping gradient	100	% $\frac{cap}{h}$
Minimum load	20	% of cap
CAPEX	800	$\frac{€}{kW_{el}}$
Lifetime	11	years
Fixed O&M costs	1.5	% of total invest
Interest rate	7	%

Table 1: Electrolyser Parameter (own assumptions based on Kopp et al. (2017) and International Energy Agency (2019)

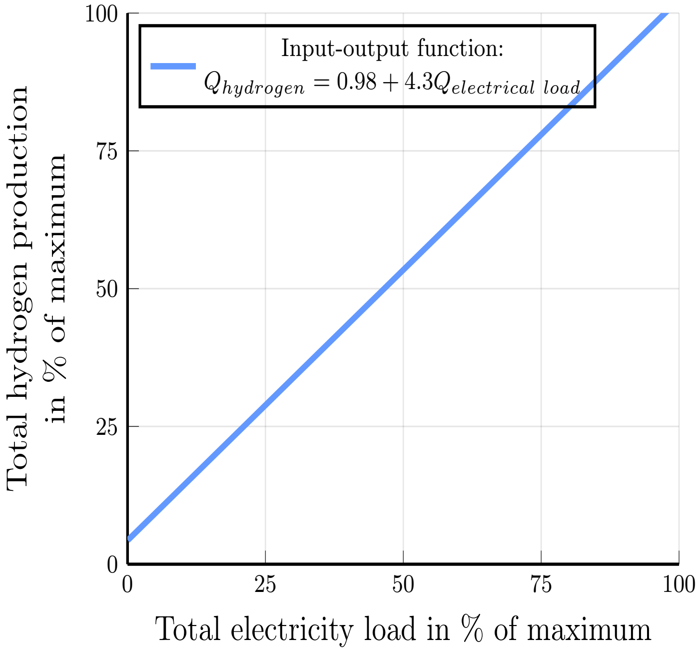

Figure 3: Electrolyser Input-Output-Function (own assumption based on Kopp et al. (2017)

4. Results

We obtain results for the operation of the electrolyser within the defined case study. These results indicate the short-term viability of the electrolyser for several wind generation realisations. For a base case, we first show the distribution of the contribution margin of the electrolyser, the corresponding short-run average costs, and the FLH as measures for the cross-commodity arbitrage and the short-term economic viability. Secondly, we assess the determinants WtP and simultaneity. Additionally, we analyse the effect on the CO_2-emission intensity of hydrogen. Lastly, the long-term viability of the electrolyser is analysed by including the fixed costs to calculate the long-run average cost, represented as LCOH.

4.1. Base case

A WtP for hydrogen of 3 €/kg and a simultaneity of 1 hour define the base case. In Figure 4, histograms illustrate the results of 1000 samples of wind generation. Thus, the distributions show how the assumed wind generation translates through the electricity price models and the electrolyser dispatch model into the electrolyser's profitability. We observe this translation with the aid of three main metrics. First, we show the total profitability of the electrolyser operation indicated by the distribution of the absolute contribution margin. Consecutively, we detangle this total viability in a price effect, indicated by the short-run average cost of hydrogen, and a quantity effect, indicated by the FLH of the electrolyser.

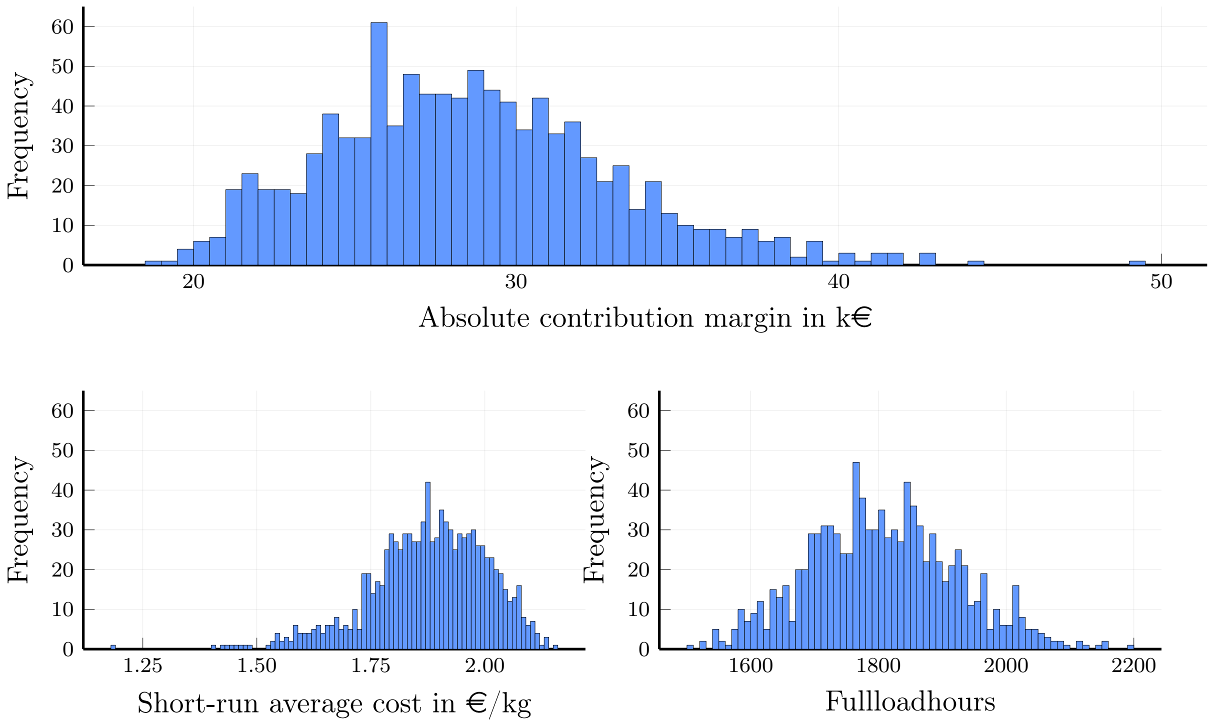

Figure 4: The distribution of the absolute contribution margin (top), the short-run average cost (bottom left), and full load hours (bottom right). The simulation has been performed for 1000 samples of wind generation, a WtP of 3 €/kg, and a simultaneity of 1 hour.

The absolute contribution margin for a year ranges from 18914€ in the worst case to 49403€ in the best case. In the mean, the electrolyser would generate a margin of 28590€ with a standard deviation of 4456€. Given a median of 28249€, the distribution is slightly right-skewed. The distribution is higher concentrated for low margins than it is for high margins. The right skewness results initially from the underlying wind profile distribution. However, its effect on the absolute contribution margin translates through two components of the model framework, the electricity prices and the wind energy availability, given by the simultaneity of RE and hydrogen production of 1 hour. The two bottom illustrations of Figure 4, therefore, show the short-run average costs of hydrogen and the FLH as an indication of the associated price effect and quantity effect of the wind generation variation on the margin of the electrolyser. The skewed wind generation distribution becomes visible in the short-run average costs as left skewness since electricity prices are low for high wind generation. The mean of the short-run average costs is 1.71 €/kg with a standard deviation of 0.13 €/kg. Thus, the operative price is below the WtP of 3 €/kg since the electrolyser runs in all hours, which allow it to generate hydrogen with costs less than the WtP. Thus, in all years, the mean of short-run hydrogen costs is below 3 €/kg with the maximum at 2.15 €/kg. The FLH, on the other hand, show a symmetrical distribution with a mean of 1806 hours and a standard deviation of 115 hours. The FLH are a good indicator for the total quantity of produced hydrogen. In the simulation, we use a normalised electrolyser size of 1 MW so that with the FLH, the expected production could be scaled to any size.

The approximated emission intensity of hydrogen is calculated with the deviation of the electrolyser production from the RE production. Other power producers connected to the grid must supply each MWh of electricity consumed and not generated by the RE plant in the same quarter-hour. As introduced in section 3, we assume two different parameters for the electricity emission intensity in order to show how different assumptions on the emission intensity of electricity supply translate into the emission intensity of hydrogen. We derive mean CO_2-emission intensities of 1.0 $kgCO_2/kgH_2$ when applying the HAEF and 4.7 $kgCO_2/kgH_2$ when applying the MEF and 3.2 $kgCO_2/kgH_2$ using the YAEF. The MEF translates into the higher mean emission intensity since the German energy mix is characterised by still significant shares of emission-intensive lignite power generation with comparably low marginal costs. Hence, deviations from the RE generation profile can cause a ramp-up of lignite plants and lead to substantial emissions.

4.2. Impact factor willingness to pay

The WtP is one decisive factor for the electrolyser's viability since it defines the electricity break-even price. The WtP depends on the specific end-use and is generally unknown. Therefore, we apply a sensitivity of WtP to the results. We simulate the electrolyser dispatch model for WtPs of 2, 2.5, 3, 3.5, 4 and 4.5 €/kg. Figure 5 illustrates the sensitivity results for the absolute contribution margin, the short-run average costs and the FLH as box plot diagrams. The centred box shows the median, the upper and lower quartile and the whiskers represent the highest and lowest value within the 1.5 interquartile range.

Intuitively, the results show an increasing contribution margin with an increasing WtP. The growth rate appears to increase with a rising WtP. The reason is the structure of the merit-order on the electricity market and the corresponding electricity price duration curve. Negative and close to zero electricity prices occur only in few hours of the year, whereas the middle part of the price duration curve is rather flat. Hence, a certain price level occurs more frequent in absolute terms, whereas very high electricity prices are again rather rare (see Figure A.12 and A.12 in the Appendix A). Each WtP translates into an electricity break-even price through the electrolyser model, determining whether the operation is economically viable. If the WtP is varied at a level such that this electricity break-even price lies somewhere in the flat part of the price duration curve, the number of operating periods increases significantly. Hence, the effect of increasing WtP translates into both a price effect, since higher electricity prices are acceptable for a profitable operation and a quantity effect, as more hydrogen can be produced in absolute terms.

The realisations of optimised FLH depending on the WtP are shown in the lower right chart. Here, the increase in generation can be noticed, particularly between 2 and 3.5 €/kg. The graph also shows that the growth in FLH decreases at a certain level, here, between 3.5 and 4.5 €/kg. The reason is twofold: first, the electricity break-even prices reach the right part of the price duration curve. Hence, economically attractive electricity prices occur less frequently, and the economic viability gets very sensitive to hydrogen price changes. Second, the FLH of the RE source, which constrains the electrolyser through the simultaneity, limits hydrogen production.

The short-run average costs show a similar trend, illustrated in the upper right chart. A higher WtP leads to an increase in short-run costs, however, with a decreasing growth rate. The volatility of the short-run costs also decreases with higher WtP. A comparably low WtP of 2 €/kg allows the electrolyser to operate in few hours of the year when electricity prices are close to zero or negative. Increasing the hydrogen price leads to a substantial increase in short-run average cost, but the growth slows down due to the reasons mentioned above of limited RE availability and high electricity prices at the right end of the price duration curve.

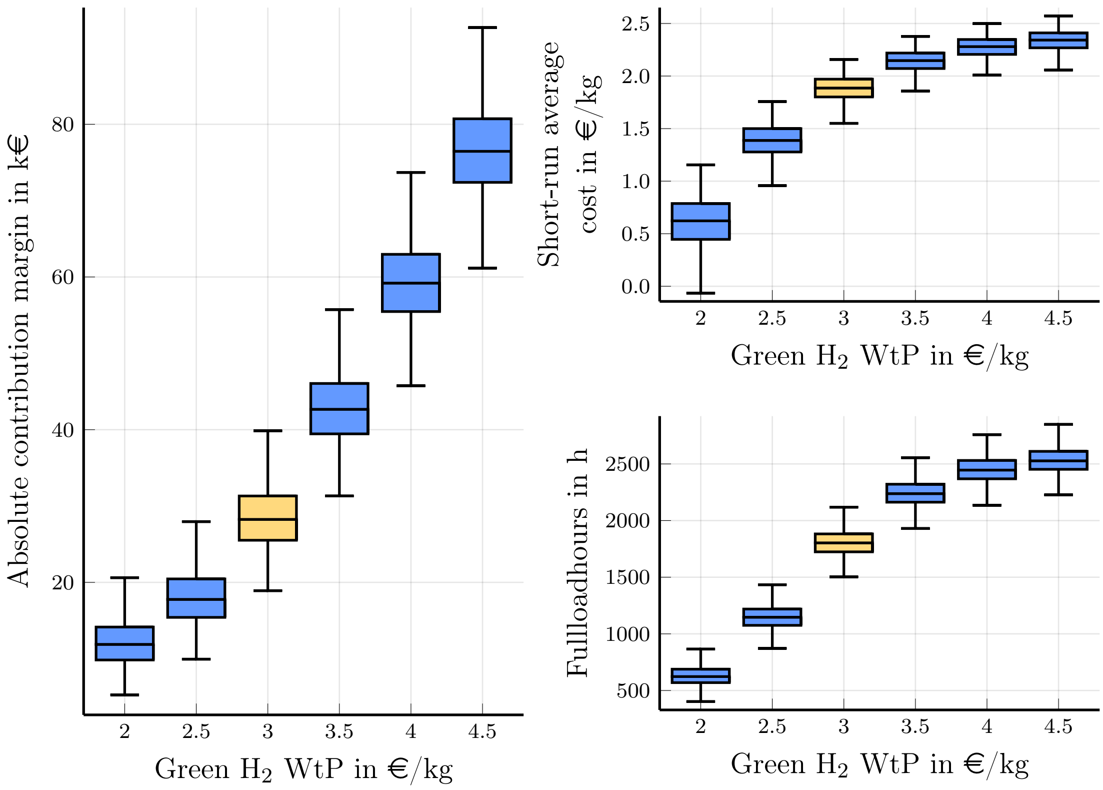

Figure 5: The distributions of the absolute contribution margin (left), the short-run average cost (top right), and FLH (bottom right) for a simultaneity of 1 hour and a range of the green hydrogen WtP from 2 €/kg to 4.5 €/kg.

4.3. Impact factor green characteristic of power supply

As second sensitivity, the simultaneity is varied with a fixed WtP of 3 €/kg and a 15 minutes interval as highest simultaneity and yearly simultaneity as lowest simultaneity. Additionally, a case without any simultaneity is simulated, where the electrolyser is not obliged to balance electricity consumption with RE generation at all. The simulation is run for a simultaneity of 15 minutes, 1 hour, 8 hours, 12 hours, 1 year and *None*. The results are presented in figure 6. On the left chart, the absolute contribution margin under varying simultaneity is illustrated. It shows that with a decreasing simultaneity, the contribution margin of the electrolyser increases from a median of 26888 € to 40192 €. With less restrictive simultaneity obligations, the electrolyser has higher operational flexibility to optimise against low electricity prices and can virtually shift the RE characteristic to periods with low electricity prices.

However, the short-run average cost remains at a similar level for most simultaneity sensitivities, as presented in the upper right diagram. Only eliminating the simultaneity leads to a more visible increase in average costs since the electrolyser can be flexibly dispatched in any period with accordingly low electricity break-even prices.

The higher profitability can mainly be explained by the increase in FLH, as indicated in the lower right diagram. The FLH remain at a relatively low level of less than 2000 hours in the first three sensitivities. Hence, the electrolyser is constraint by both the RE profile and the electricity prices. With decreasing simultaneity, the electricity prices gradually become the limiting constraint, with the RE characteristic being shifted between the periods. In the case of yearly simultaneity, the total FLH of the RE generator become the limiting constraint, which can be seen by the additional FLH when removing the simultaneity criterion.

4.4. Emission intensity

A less restrictive simultaneity of RE and hydrogen generation increases the operational flexibility of the electrolyser and improves economic viability. A drawback is a potential increase in emissions caused by additionally induced electricity generation of conventional power plants. Figure 7 shows the mean emission intensity of hydrogen when applying different electricity emission intensity measures on the sensitivities. We define a quarter-hourly simultaneity as a perfect balancing of RE and hydrogen generation as a lower benchmark. Thus, the electrolyser is entirely supplied by the RE plant, and no additional CO_2 is emitted.

The mean specific emission intensity of hydrogen increases with higher WtP, but with a different trend depending on the assumed electricity emission factor (left chart). Low electricity prices mainly occur when residual demand[6] is low, which is often when RE feed-in is high. With increasing residual demand, the electricity price rises and the share of conventional power plants in the electricity mix increases. Hence, a

[6] Defined as total demand less RE feed-in, hence, the demand which conventional power plants must supply.

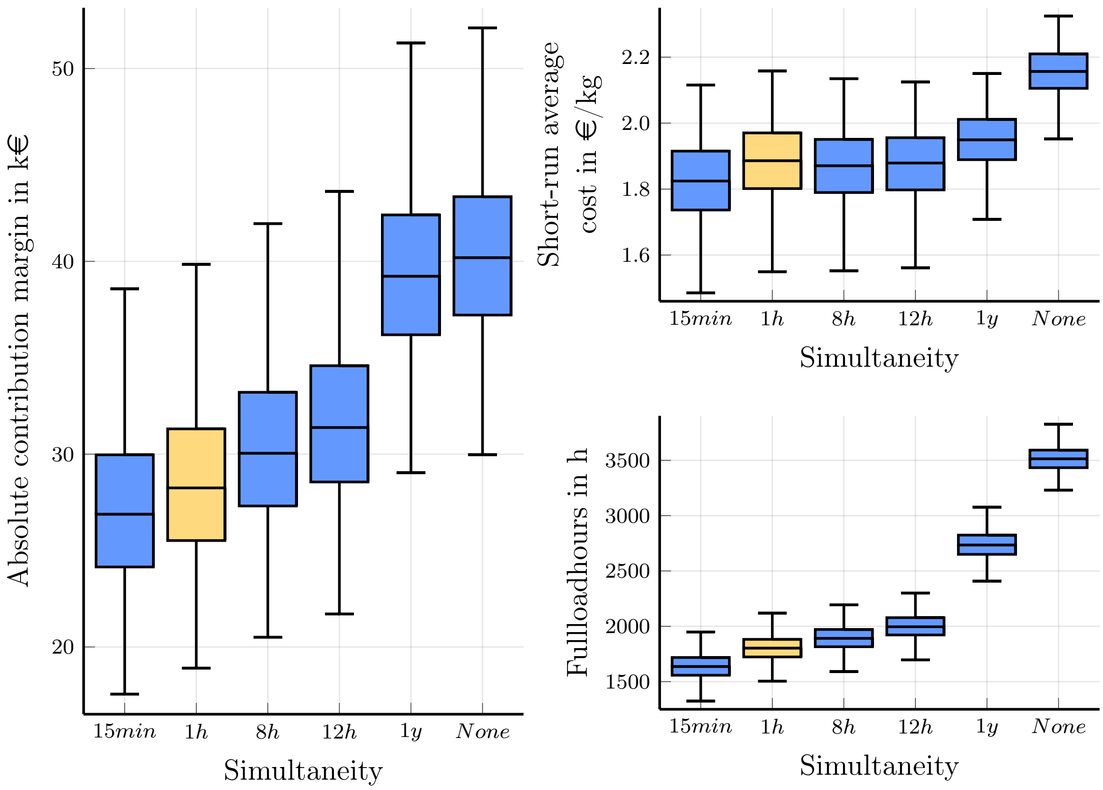

Figure 6: The distribution of the absolute contribution margin (left), the short-run average cost (top right), and FLHs (bottom right) for a green hydrogen WtP of 3 €/kg and a range of the simultaneity from 15 minutes to one year. Additionally, the figure illustrates the case without any restriction by a RE plant profile.

higher WtP for green hydrogen enables the electrolyser to produce in more hours with comparably higher electricity prices and a larger share of conventional power plants in the supply mix. Thus the marginal emission factor increases.

With a higher WtP, the average emission intensity of hydrogen first increases for both emission measures. The YAEF is independent of the marginal power plant and is constant throughout all periods. The emission intensity of hydrogen only varies with the share of electricity that the RE plant does not supply. The hydrogen emission intensity variation is less than the MEF, but it also increases with higher WtP. However, it decreases with a WtP for green hydrogen of above 3.5 €/kg. While the absolute emissions rise with higher WtP, the total hydrogen generation also increases; however, the output increases stronger than the total emissions. Hence, the average emission intensity reduces. Applying the MEF, the emission intensity of hydrogen shows a similar trend with a more substantial increase in emission intensity with higher WtP. This can be explained by the fact that lignite power plants are often marginal suppliers with low electricity break-even prices. However, with increasing WtP–and accordingly increasing electricity break-even prices–other conventional generation technologies, such as coal or gas plants, are marginal, with a comparably lower emission intensity per MWh of electricity. Additionally, more hydrogen is produced due to higher FLH when the WtP is higher. This also reduces the average emission intensity of hydrogen, as the remaining emissions are shared over a larger output.

A variation of the simultaneity also has an impact on the emission intensity of hydrogen. The simultaneity of 15 minutes represents a full balancing of RE and hydrogen production so that CO_2 emissions are zero. Deviations from the RE generation profile need to be supplied by other generators. Applying the YAEF leads to an overall increase in the emission intensity of hydrogen. The shift from quarter-hourly to hourly simultaneity causes a steep increase from 0 to 3.2 $kgCO_2/kgH_2$. From hourly to 12-hourly simultaneity, the emission factor almost doubles. A yearly balancing of RE and hydrogen production results in a mean emission intensity of 12.3 $kgCO_2/kgH_2$ when applying the YAEF of electricity, which is slightly above the emission intensity of conventional hydrogen from steam methane reforming with approximately 10 $kgCO_2/kgH_2$ (International Energy Agency, 2019). If no balancing of RE and hydrogen production is required, the average hydrogen emission intensity amounts to 30.2 $kgCO_2/kgH_2$, hence, around three times higher than conventional hydrogen. Using the MEF as the emissions factor of consumed electricity, the average emissions intensity of hydrogen is slightly above the YEAF results for most cases. Only with yearly simultaneity, the MEF results in a lower average hydrogen emission intensity. Without any simultaneity of RE and hydrogen production and assuming that the marginal power plant always supplies the electrolyser, the average emission intensity is 33.2 $kgCO_2/kgH_2$.

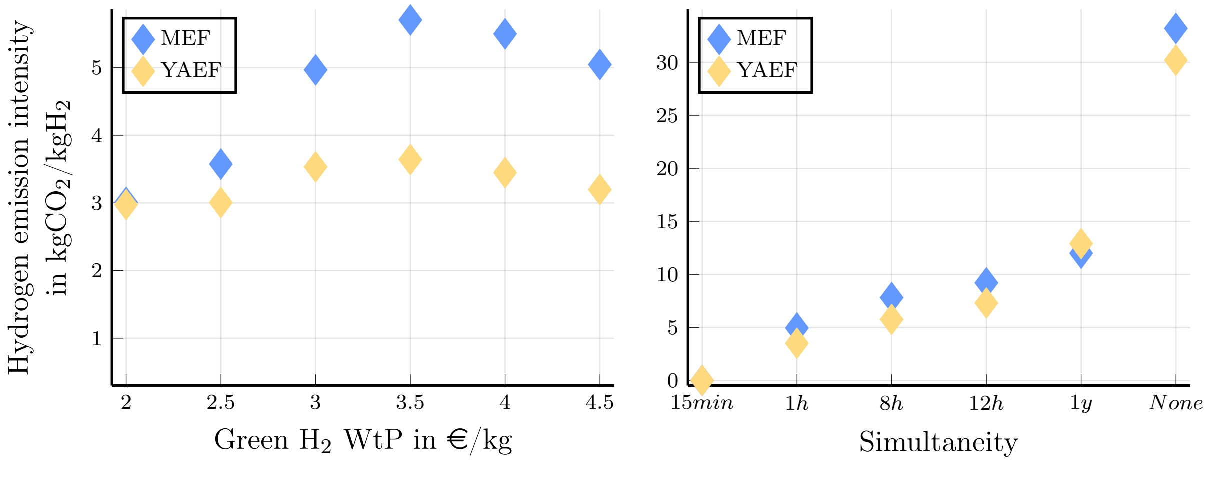

Figure 7: The hydrogen emission intensity in kg CO_2/kghydrogen indicated by the MEF, HAEF, and YAEF for both the green hydrogen (left) and the simultaneity (right) sensitivities.

4.5. Long-term viability

The dispatch model optimises the electrolyser operation for one year and obtains the short-run average cost. Based on these results, we compute the long-run average cost, here indicated by the LCOH. Note that the computation of the LCOH based on the short-run dispatch model is simplified. The variation of electricity prices of one year concerning wind generation does not provide a comprehensive representation of the life cycle operation costs an electrolyser would face in a transforming energy system. Nevertheless, taking the capital and the fixed operational costs of an electrolyser into account may put the short-term results into perspective.

Figure 8 illustrates the distribution of the realised LCOH for the benchmark case assuming a WtP of 3 €/kg and a simultaneity of 1 hour. The vertical lines mark the WtP and the median of the LCOH-distribution. In this base case, the LCOH ranges from 5.6 €/kg in the best case to 7.7 €/kg in the worst. The median is 6.6 €/kg. Compared with the WtP, this obtains a financing gap between 2.6 €/kg and 4.7 €/kg. In the long-term the electrolyser is not viable for any wind generation realisation. In 50 % of the cases, the financing gap would be lower than 3.6 €/kg. The distribution resembles the FLH distribution in Figure 4 since the effect of the investment cost on the LCOH solely depend on the FLH. The investment costs stress the quantity effect so that it dominates the LCOH distribution.

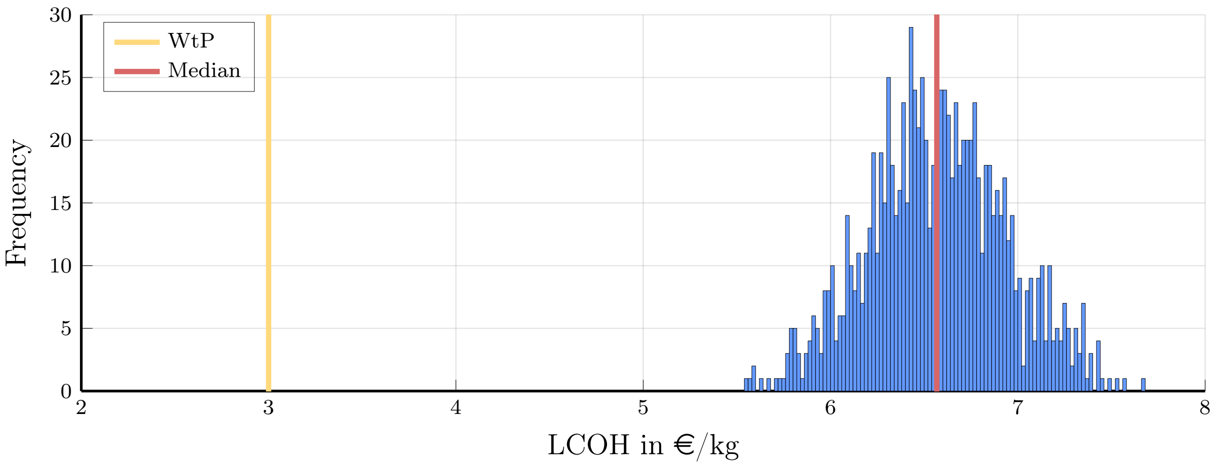

Figure 8: The distribution of the LCOH in €/kg, the assumed WtP of 3 €/kg and the median. The simulation has been performed for 1000 samples of wind generation, green hydrogen WtP of 3 €/kg, and a simultaneity of 1 hour.

The WtP for green hydrogen and the simultaneity determine the size of the financing gap. Figure 9 shows the LCOH for both sensitivities. The left box plot shows that reducing the WtP to 2 €/kg increases the median LCOH to 14,5 €/kg while raising the WtP to 4.5 €/kg decreases the median LCOH to 5.7 €/kg. Simultaneously, the range of possible values decreases with a higher WtP. While a WtP of 2 €/kg implies a dispersion between 9.6 and 19.7 €/kg, the LCOH disperse between 5.1 and 6.3 €/kg for a WtP of 4.5 €/kg. The quantity effect an increasing WtP has on the electrolyser operation can explain the decrease of both the median and the dispersion. The electrolyser runs in more hours as they become viable with the higher WtP. On the one hand, this increases the short-run average costs as the electrolyser runs in hours with higher electricity prices. On the other hand, it increases the total hydrogen production of a year. The investment cost is distributed over more kilograms of hydrogen so that the LCOH decrease. The latter effect dominates the former so that, in total, the median of the LCOH decreases with a higher WtP. As the electrolyser's FLH converges with the FLH of the RE generator, the quantity effect diminishes, and the LCOH stay at a lower level of 5.7 €/kg. The dispersion decreases as the electrolyser operates at electricity prices in the middle part of the price duration curve (see Figure A.11 and A.12 in the Appendix A), where the dispersion of prices is low. Very low electricity prices have a higher dispersion, which translates into the dispersion of LCOH when the WtP is lower. Therefore, at low FLHs, the LCOH disperse more than for higher FLHs.

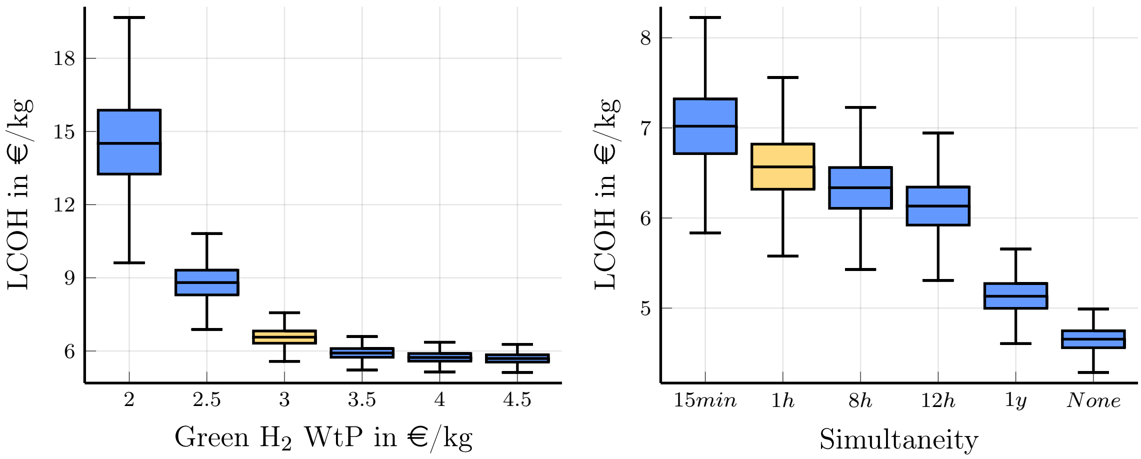

Figure 9: The distribution of the LCOH in €/kg for both the green hydrogen (left) and the simultaneity (right) sensitivities.

The box plot on the right in Figure 9 illustrates the sensitivity of the LCOH distribution on the simultaneity. Increasing the simultaneity to 15 minutes increases the median of the LCOH to 7.0 €/kg while a simultaneity of a year reduces the LCOH to 5.1 €/kg. Operating without the constraint of simultaneity with RE generator yields LCOH of 4.7 €/kg. The dispersion decreases analogously to the median. For a simultaneity of 15 minutes, the LCOH disperse on a range of 2.4 €/kg between 5.8 €/kg and 8.2 €/kg. For a yearly simultaneity, this range decreases to 1.1 €/kg and is 0.7 €/kg without simultaneity restrictions. Both the price and quantity effect drive these observations. With a lower simultaneity, the electrolyser shifts its consumption more flexibly into periods with low electricity prices. From the price effect perspective, short-run costs can be reduced by consuming electricity at lower prices. From the quantity effect perspective, the electrolyser can increase its FLH by shifting its consumption from hours that are not viable into hours which are, so that also the FLH of the electrolyser increase with lower simultaneity. The dispersion of the LCOH decrease with a lower simultaneity since the dispersion of the quarter-hourly wind profiles is higher than the dispersion of the integral under the electricity price duration curves. Relaxing the binding constraint of simultaneity between electricity consumption and production decreases the impact of wind generation as a determinant of the short-run costs and emphasises the impact of the electricity price profiles. The latter disperse less.

Both a higher WtP and a lower simultaneity decrease the median and dispersion of the LCOH and the financing gap of an electrolyser investment. The effect of the WtP diminishes as the FLH of the electrolyser converge with the FLH of the RE plant. The lower simultaneity has a particular effect when the electrolyser can reduce the correlation between the RE generation and the electricity price, which are shifted within the day and between seasons.

5. Discussion

The presented numerical results apply to the specific case study, though they show insights into the economics and the regulation of grid-connected electrolysers. From a technical perspective, the connection to the public electricity grid gives the plant the option for continuous operation. Economically, operating constraints are given by the electricity price and the WtP for green hydrogen. Under current market conditions, a grid-connected electrolyser is economically not viable since profits from cost-optimised short-term dispatch are not sufficient to cover long-term fixed costs. The major drivers for the viability are electricity prices, WtP for hydrogen, and the availability of RE supply under a regulation of grid-connected electrolysers. These drivers are discussed in the following chapter employing three implications: the impact of a simultaneity constraint, the RE dependency of the financing gap, and the design of a hydrogen market.

First, the simultaneity is a decisive determinant of the viability of an electrolyser. The simultaneity criterion has recently been discussed, e.g., in the context of a surcharge exemption in Germany[7] and the RED II[8] in the EU. However, both the German and the EU legislation foresee a criterion of temporal correlation with a different approach. While in the context of RED II, a high simultaneity of 15 minutes is under consideration, Germany's Renewable Energy Act allows the operator to balance RE and hydrogen production with RE certificates, which is, in fact, a simultaneity of one year (Renewable Energy Act, 2021).

In the former case of high simultaneity, the electrolyser dispatch must consider both the break-even electricity price and the availability of RE generation. Hence, the FLH can be substantially reduced. In systems where electricity prices are mostly negatively correlated with RE generation, the plant can still operate in a significant number of periods. In the long-term, the comparably lower FLH translate into higher LCOH. In the latter case, a low simultaneity improves the economic viability of the electrolyser due

[7] Germany's Renewable Energy Act 2021 exempts electrolysers from the renewable energy surcharge (EEG)–a surcharge financing the expansion of RE capacities–provided that they comply with a set of criteria Renewable Energy Act (2021).

[8] The Directive 2018 on the promotion of the use of energy from renewable sources–often referred to as "RED II"–sets targets on the use of RE in the transport sector. As part of this, hydrogen from electrolysis using RE sources is admitted as renewable fuel European Commission (2018).

to increased flexibility in the operation. While electricity prices and WtP are constraining the dispatch decision for every period by setting an implicit electricity break-even price, the yearly simultaneity only influences the FLH by setting an upper limit given by the FLH of the RE plant. Thus, two effects improve the economic viability: first, the plant can be dispatched in each period with sufficiently low electricity prices independent from the RE generation in the respective period–if the FLH of the RE plant is not constraining. Second, the increased FLH lead to higher profits to cover fixed costs so that the LCOH are reduced. However, the green characteristic of the produced hydrogen can be controversially discussed. The impact on CO_2 emission intensity of hydrogen can be significant if the shift in demand causes ramping of conventional power plants. On the other hand, since the electricity sector is part of the EU ETS, the total CO_2 emissions are capped, and the ramping of conventional power plants would not lead to additional emissions on the system level. As this issue is out of the scope of this paper and also applies to other power consumers, it is referred to according publications (Huber et al., 2021; Fleschutz et al., 2021; Braeuer et al., 2020).

The findings show a trade-off when regulating grid-connected electrolysers with a temporal criterion. Depending on the choice of simultaneity, the FLH, the emission intensity of hydrogen, and the total cost of hydrogen production (LCOH) are varied, which determine the total hydrogen output and the economic viability of the electrolyser. Applying rigour rules ensure a low CO_2 emission intensity of hydrogen. However, they also set constraints on the FLH and make the investment unprofitable. Implementing less strict rules improve the economic viability, but they can also lead to significant additional CO_2 emissions.

Second, the results show that the electrolyser investment is, under current conditions, not profitable in any of the sensitivities. A weather-dependent financing gap remains. It is unclear who should fill this gap and bear the risk of its RE depending on size. The funding body and private investors may share the risk of filling the financing gap if the market ramp-up of green hydrogen is desired. Our stylised case study for an electrolyser in Germany shows that the median of the financing gap in the base case is 3.6 €/kg. Thus, in 50 % of the samples, a support of 3.6 €/kg would be sufficient to finance the electrolyser. Since the financing gap disperses between 2.6 €/kg and 4.7 €/kg, a substantial risk remains in closing the gap. An appropriate instrument should condition the volatility of RE production to fairly share the risk between both parties. This risk of over- or under-compensation does not exclusively occur with electrolyser investments but also in other cases or RE-dependent energy consumption. Tenders or contracts for difference are current examples of how regulators may address the RE-dependent risk.

Instruments aiming to increase the WtP to close the financing gap or adjust the simultaneity to guarantee the consumption of RE generated electricity also affect the RE-dependent risk of the electrolyser viability. The WtP determines on which levels of the price duration curve the electrolyser operates. The price dispersion is particularly high in the price duration curve's low and high peak levels, while in the middle body, the dispersion is comparably low. The regulation of simultaneity establishes a dependency of the business case on the RE production. The natural volatility of RE sources translates into the profitability of an electrolyser–the higher the simultaneity, the higher the dependency, and the higher the risk for an investor.

We show how the WtP and the simultaneity are levers for the size and dispersion of the financing gap. Increasing the WtP is particularly effective concerning the LCOH of an electrolyser investment in the flat areas of the electricity price duration curves since an increase of the WtP leads to a comparably steep increase of FLHs. The availability of RE generation, however, limits the effect of the WtP. Simultaneity is particularly effective in cases when RE generation and electricity prices are strongly correlated. In these cases, the electrolyser operator benefits from shifting its production away from the RE generation profile. Thus, RE power plants that are highly correlated with the system residual load profile would benefit from a low simultaneity as this would implicitly allow them to store their generation without losses and sell it during a period with higher prices.

Third, the results contribute to the conception of a future hydrogen market design. Today, hydrogen trade is mostly based on bilateral long-term contracts between industrial consumers and producers. The ramp-up of hydrogen as an energy carrier is expected to establish an entirely new market with more diverse market actors over a geographically larger area (Brändle et al., 2021; Schlund et al., 2021). The market design for a prospective hydrogen market has not been discussed in the literature in much detail. Though we do not look further into this topic, our results give some insights and indications.

In the short-term, the operator will always choose to maximise the profit from buying electricity and selling hydrogen. As a consequence, an implicit electricity break-even price determines whether the electrolyser is dispatched in a period. Hence, the hydrogen price and the electricity price are decisive parameters for the dispatch decisions. The operator does not consider operational fixed costs and the annuity. Thus, in the long-term, aggregated profits must be sufficient to cover also these costs to guarantee a profitable investment. However, the numerical results indicate that this condition could not be satisfied in the long-term. While the quantitative results strongly depend on the numerical assumption of the case study, their interpretations are also applicable to other parameters and set-ups.

Consequently, the WtP for green hydrogen, i.e. the hydrogen price, would increase in the long-term since hydrogen producers would leave the market if fixed costs cannot be compensated. With a higher hydrogen price, producers would earn higher profits and cover their fixed costs. During the market ramp-up, it is uncertain whether the market mechanisms will be working accordingly due to several distorting effects, such as political interventions and support schemes, different taxation of hydrogen and its close substitutes. Furthermore, investors are currently attracted by high expectations in a future hydrogen market, giving them incentives to enter the market. However, the investment is unprofitable, e.g., due to strategic reasons or to create positive spill-over effects with vertically integrated RE plants.

During the market ramp-up, a marginal cost-based hydrogen market will be challenging to create adequate incentives for investors. Another option could be a different market design comparable with early natural gas markets in Europe, where bilateral contracts set binding parameters for prices and quantities to ensure long-term profitability for investors (Heather, 2021). The topic of a future hydrogen market design will require additional research in the future.

6. Conclusions

Hydrogen from RE sources is increasingly considered a supplement in energy systems with high RE penetration rates due to its versatile end-use applications and storage potentials. However, as a secondary energy carrier, it strongly relies on the characteristics of other resource markets. In the case of grid-connected electrolysers, this dependence concerns particularly electricity markets and, hence, RE generation.

This paper presents a methodology for assessing a grid-connected electrolyser's economic viability, optimising its operation against the sequential electricity day-ahead and intraday markets. In order to ensure a renewable characteristic of the produced hydrogen, the electrolyser's electricity consumption and the RE generation are coupled by a criterion of simultaneity. The analysis builds upon a mixed-integer linear program, which uses a regression model's synthetically derived electricity price time series. Variation is generated by a stochastic Monte Carlo simulation of wind power forecasts and forecast errors.

The results are analysed from a short and long-term perspective of the electrolyser investment. While a sensitivity analysis of the WtP for green hydrogen and the simultaneity criterion shows that the investment is not profitable in any situation, it gives some important insights into the operation of grid-connected electrolyser in a transforming energy system: First, the introduction of a temporal criterion –represented as the simultaneity– has a significant impact on the economic viability and the total cost of hydrogen. There is a trade-off between FLH, renewable characteristics, and total cost per output. Second, due to the characteristics of the wholesale electricity markets, a higher WtP for green hydrogen and relaxation of the temporal criterion can lead to substantial additional emissions in the electricity system since conventional power plants may be forced to ramp up. Whether this effect holds within an emission trading system, such as the European Emission Trading System, is out of the scope of this paper. Third, the volatility of RE generation directly translates into the risk of an electrolyser investment and into its potential support mechanisms to incentivise a hydrogen market ramp-up.

Further research needs to focus on the economics of grid-connected electrolysers and their interdependence with electricity markets and RE generation. The effect of a transforming energy system with increasing shares of RE generation needs to be assessed for a variation of weather realisations. Furthermore, the design of support mechanisms considering our findings requires additional research. The conceptualisation of future hydrogen markets, their pricing mechanisms, and incentive structures could also be the subject of further research on this topic.

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Appendix A. Appendix

Appendix A.1. Regression Results

The regression results for the day-ahead market are illustrated in Figure A.10. Based on the data for the years 2015-2019 a function is fitted to each month of the year.

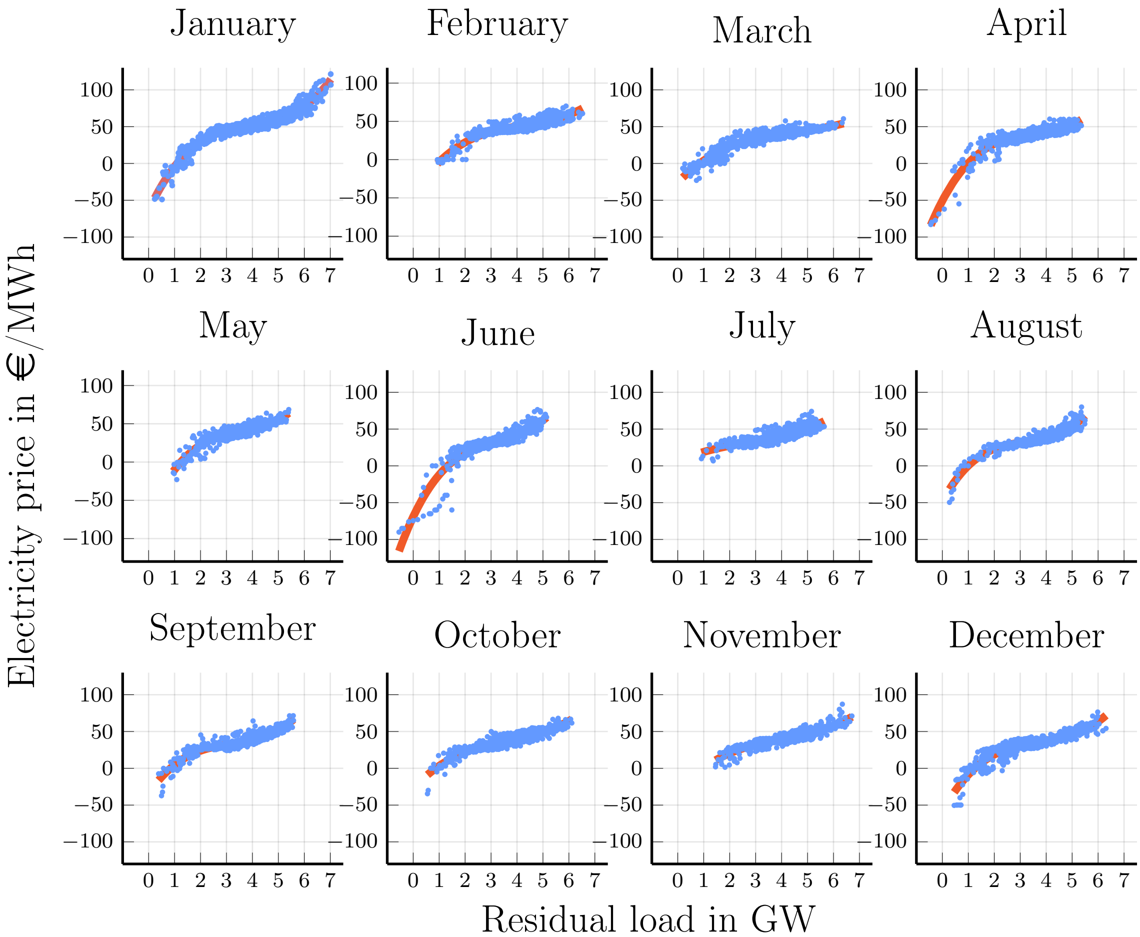

Figure A.10: Regression results for the day-ahead market.

Analogously, the intraday market prices are regressed on the day-ahead market prices and the wind generation forecast error. Table A.2 shows the regression results indicating that the applied independent variables are significant within this model.

Appendix A.2. Monte Carlo simulation

To obtain synthetic electricity market price time series for both the day-ahead and the intraday market, we generate synthetic time series of the independent variables used in the parametric models of the electricity market, i.e. wind generation forecast and wind generation forecast errors. We follow Papaefthymiou and

Table A.2: Regression results for the intraday market

	Coef.	Std. Error	t	Pr(>|t|)	Lower 95%	Upper 95%
(Intercept)	1.80256	0.192212	9.38	<1e-20	1.42582	2.1793
DA prices	0.971656	0.00459027	211.68	<1e-99	0.962659	0.980653
Forecast error	-0.976845	0.0194165	-50.31	<1e-99	-1.0149	-0.938789
(Forecast error)^2	-0.0220511	0.0023063	-9.56	<1e-20	-0.0265715	-0.0175307

Klockl (2008) by parameterising the transition probabilities of a Markov chain with 15 states on both parameters separately. Note that we do no take into account the correlation between the parameters. However, we use the relative forecast errors instead of the absolute ones so that the absolute errors still scale with the wind generation forecast. The transition probability matrix includes the probabilities to change from one state to another to the next period, so that we obtain for every state a cumulative distribution function of possible next states.

For each time step of the simulation horizon we draw random numbers from a uniform distribution $\mathcal{U}(0,1)$. Plugging the random number into the inverse of the cumulative distribution function, obtains the next state within the Markov chain (Amelin, 2004). The process we continue for the entire simulation horizon and repeat it for the number of samples we generate. The day-ahead prices are then calculated based on Equation (7). Figure A.11 shows the range of resulting price duration curves. The intraday price are computed based on Equation (8), also using the synthetic day-ahead prices. The results are shown in Figure A.12.

Appendix A.3. Annuity and LCOH computation

The annuity of the electrolyser investment is computed based on Equation (A.1). Multiplying the CAPEX with the capital recovery factor obtains the annutiy.

$$\text{annuity} = CAPEX * \frac{(1+i)^n * i}{(1+i)^n - 1} \tag{A.1}$$

The LCOH are computed according to Equation (A.2). The total costs of *annuity*, fixed operation and maintenance cost FOM, and variable costs C_t are divided by the total hydrogen production Q^{total}.

$$\text{LCOH} = \frac{annuity + C^{FOM} + \sum_t^T C_t}{Q^{total}} \tag{A.2}$$

Appendix A.4. Annotation

Table A.3: Model indices, parameters and variables

Name	Unit	Definition
Sets		
$t, j \in T$		Time periods
$m \in M$		Electricity markets (intraday, day-ahead)
Parameters		
p^{H2}	EUR/kg	Willingness-to-Pay for green hydrogen
p^{DA}	EUR/MWh$_{\mathrm{el}}$	Day-ahead price
p^{ID}	EUR/MWh$_{\mathrm{el}}$	Intraday price
p	EUR/MWh$_{\mathrm{el}}$	Electricity price
δ	-	Time scaling
cap	MW$_{\mathrm{el}}$	Electrolyser capacity
α	EUR/MWh$_{\mathrm{el}}$	Electricity price surcharges
β	-	Minimal load as fraction of the capacity
γ	-	Simultaneity of electricity production and consumption
σ	-	Capacity ratio of electrolyser and RE plant
re	-	(current) RE capacity factor
q^{res}	MW$_{\mathrm{el}}$	Residual load
ϵ_0	EUR/MWh$_{\mathrm{el}}$	Intercept coefficient of the day-ahead regression
ϵ_0	EUR/MWh$_{\mathrm{el}}{}^2$	Coefficient of the residual load in the day-ahead regression
ϵ_0	EUR/MWh$_{\mathrm{el}}{}^3$	Coefficient of the squared residual load in the day-ahead regression
ϵ_0	EUR/MWh$_{\mathrm{el}}{}^4$	Coefficient of the cubic residual load in the day-ahead regression
ζ_0	EUR/MWh$_{\mathrm{el}}$	Intercept coefficient of the intraday regression
ζ_1		Coefficient of the day-ahead price in the intraday regression
ζ_2	EUR/MWh$_{\mathrm{el}}$	Coefficient of the relative forecast error in the intraday regression
ζ_3	EUR/MWh$_{\mathrm{el}}$	Coefficient of the squared relative forecast error in the intraday regression
$annuity$	EUR/a	Annuity
$CAPEX$	EUR	Capital expenditures
i	%	Interest rate
n	a	Years
Variables		
$Contribution\ margin$	EUR	Total contribution margin
R	EUR	Revenue
C	EUR	Cost
C^{FOM}	EUR	Fixed operation and maintenance cost
C_t	EUR	Variable cost
Q	kg	Hydrogen production
L	MW$_{\mathrm{el}}$	Load
B	-	Binary variable to determine whether plant is switched on/off
FE	-	Forecast error
$LCOH$	EUR/kg	Levelized cost of hydrogen

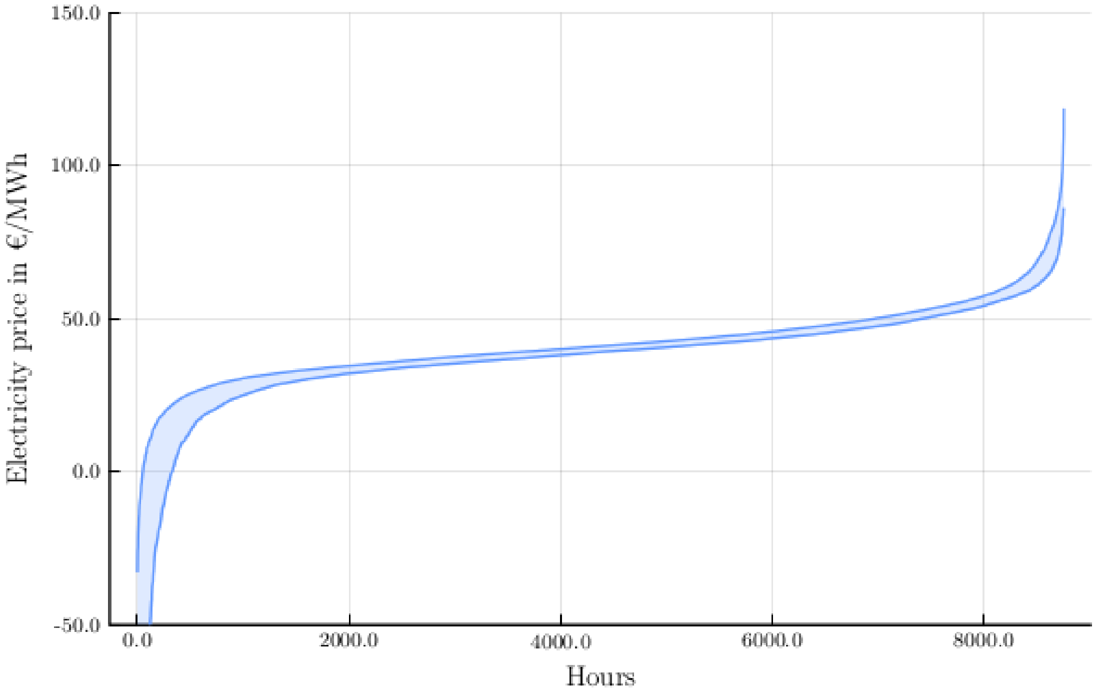

Figure A.11: The dispersion of the resulting day-ahead price duration curves of 1000 samples.

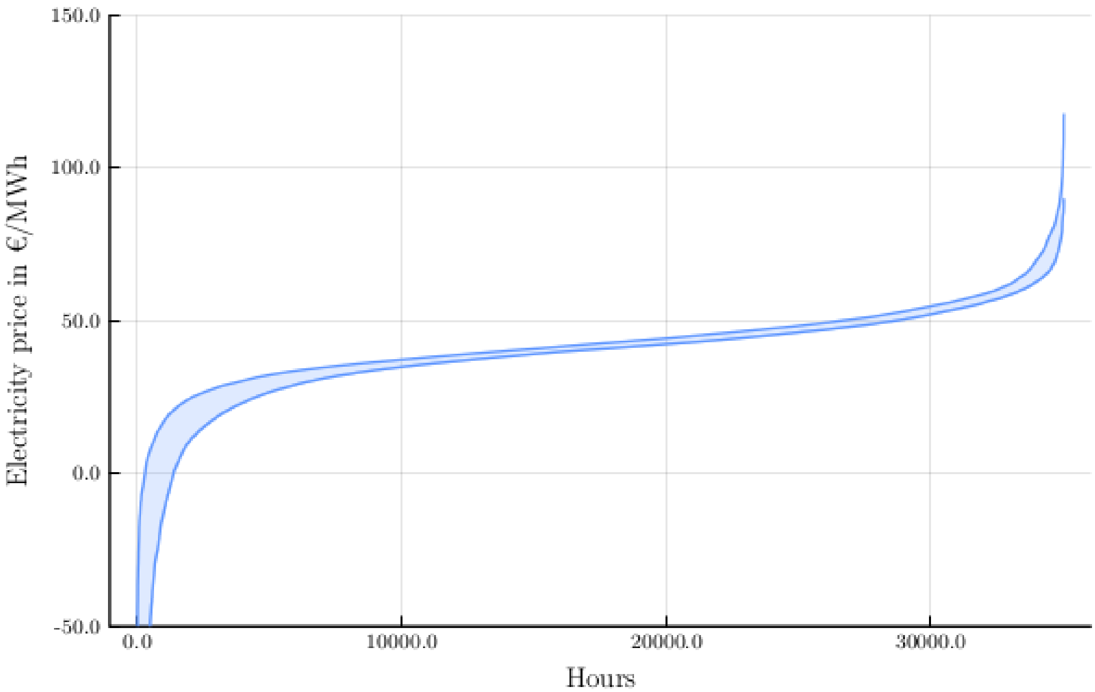

Figure A.12: The dispersion of the resulting intraday price duration curves of 1000 samples.