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Abstract

Hydrogen is viewed as a promising supplement in future energy systems with high penetration rates of renewable energy (RE) generation. As conversion technology between the two secondary energy carriers, hydrogen and electricity, particularly grid-connected electrolysers, have a role to play. During the market ramp-up, grid-connected electrolysers could cause unwanted side-effects through inducing additional CO_2 emissions from the power sector. Since the reduction of CO_2 remains the overall goal, a simultaneity obligation between RE generation and hydrogen production for the dispatch are being discussed to limit associated emissions from an electrolyser's energy consumption. 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 dispatch. Within a case study representing the current state of the German electricity market, the effect of simultaneity on the electrolyser's dispatch is assessed. The results show that the simultaneity reduces the CO_2 emission intensity of hydrogen while constraining the profits from cost-optimal dispatch. The simultaneity represents implicit storage of the RE generation's green characteristic, which allows the electrolyser to shift RE production to low price periods. Depending on the simultaneity interval, this affects both the average contribution margin and the risk of the electrolyser dispatch. Regulations aiming at the interface between hydrogen and electricity must consider the trade-off between the economic viability of electrolysers, full load hours, and the associated emissions of electricity-based 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). This transformation can be achieved by electrification of natural gas and oil

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applications, e.g., through heat pumps or electric vehicles, or by substituting hydrocarbons with climate-neutral gases like hydrogen or synthetic natural gas (Rosen and Koohi-Fayegh, 2016). Hydrogen embodies characteristics that complement well the properties of electricity, e.g., it has a higher economic efficiency than electricity in some final energy conversion processes, such as heavy road transport, in high-temperature industry applications (Dodds et al., 2015; Parra et al., 2019), and steel production. However, its production also relies on the conversion of primary energy resources like natural gas, oil, solar, or wind (Acar and Dincer, 2014). CO_2 emission reduction can only be achieved if no additional greenhouse gases are emitted for the production of hydrogen. A promising technology is, therefore, to produce renewable hydrogen from renewable energy (RE) sources and water electrolysis (Rosen and Koohi-Fayegh, 2016). The latter is referred to as power-to-gas (PtG) technology, which uses electricity to split water into hydrogen and oxygen. However, so far, renewable hydrogen is economically not efficient in any final energy sector (Buttler and Spliethoff, 2018; Abdin et al., 2020). Most energy systems still have substantial fossil generation in their electricity supply mix; hence, producing hydrogen from non-renewable energy sources does not reduce emissions. Significant RE generation capacities are needed to supply PtG with electricity while simultaneously tying the production of hydrogen to their generation profile (Schlund et al., 2022). Therefore, PtG plants operating with RE supply from volatile generation face price and quantity risks. The need for sufficient investment incentives for electrolyser operators without sacrificing the bond to RE generation poses the question of how investment and dispatch regulations should be aligned.

The economics of power-to-hydrogen conversion has recently been subject to broad research. 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). The variable costs of a PtG plant are predominantly determined by electricity prices, which are increasingly characterised by the volatility of RE generation. The electricity procurement strategy significantly affects the PtG business case and the greenness of the supply. It can take three distinct forms: (i) The PtG plant is co-located and physically connected with a RE generation plant (Ferrero et al., 2016). 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). If the RE generator and the public grid are not connected, hydrogen sales also need to cover the total cost of electricity generation (Brändle et al., 2021). (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; Hurtubia and Sauma, 2021). Moreover, (iii) a grid-connected PtG plant can be optimised against electricity market prices to maximise hydrogen production at minimal costs (Nguyen and Crow, 2016). In the third case, the PtG plant is more independent from volatile RE sources and can thus increase its output; however, indirect CO_2 emissions can be induced unless the electricity is entirely produced from RE (Huber et al., 2021). The close tie between PtG plants and RE generators creates synergies between the assets since electrolysers can mitigate the decline of RE market values with increasing RE shares in the energy system. In periods with RE generators being marginal suppliers and PtG plants being marginal consumers, the latter determines the market price through translating the price of hydrogen into an electricity break-even price (Ruhnau, 2021).

Each power purchase strategy yields economic and operational constraints for the PtG dispatch, either through the availability of power supply or through electricity cost. Although electricity is physically a homogeneous commodity, its environmental impact–e.g., measured as emission factor for electricity–varies temporally and spatially. The emission factor depends on the generation technology and, more precisely, on the used primary energy carrier (Weber et al., 2010). It is vital to consider the temporal and spatial characteristics of power supply since a grid-connected PtG plant receives its renewable characteristic from the power source. This temporal characteristic can be expressed by the *simultaneity* of the power generation from the RE source and the power consumption, which will be of particular interest in this paper.

Currently, hydrogen can either be sold to industrial consumers at (nearly) fixed prices (Luck et al., 2017) or sold as a close substitute to natural gas (Haeseldonckx and D'haeseleer, 2007). The selling price 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) may be sold. In the future, an equilibrium price of hydrogen at competitive hydrogen markets will equal the average cost of hydrogen production (Green et al., 2011). Since hydrogen is currently mainly used as a feedstock in industrial processes, there are only vague estimates on a possible equilibrium price. Thus, literature either considers inelastic demand in 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).

In the course of the hydrogen market ramp-up, policymakers are aiming to set incentives for investments in electricity-based hydrogen production. These incentives include substantial subsidies (Lambert and Schulte, 2021). However, to prevent that these subsidies cause indirectly higher CO_2 emissions through the electrolyser's electricity consumption, additional dispatch criteria to differentiate green electricity are scientifically and politically discussed. In these discussions, one repeatedly mentioned criteria is an obligation on the simultaneity between RE generation and electrolyser production. While the original rationale behind this obligation is the prevention of unwanted side-effects in the electrolyser dispatch from investment subsidies, it may distort the original investment incentive. These possible distortions of the simultaneity obligation on the investment incentive have not been taken into consideration so far. In this paper, we assess the structural form of these distortions that policymakers can consider when designing dispatch-oriented criteria for green energy subsidies. Therefore, we focus on a grid-connected electrolyser, which purchases electricity at spot markets and is obliged to consume electricity from RE plants. We explicitly consider and vary the simultaneity to assess four aspects of the obligation on the electrolyser dispatch: the general value generated by the electrolyser, the risk from varying RE generation, the sensitivity on the price relation between hydrogen and electricity, and the translation of associated carbon emissions.

We develop a model framework including a mixed-integer-linear program to determine the optimal dispatch 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 and full load hours (FLH). We vary the simultaneity interval and assess its structural impact on the viability and associated emissions of the electrolyser.

The results show the impact of a simultaneity obligation on the viability of an electrolyser. In case of a low simultaneity, the allowance to store the green characteristic of the RE generation significantly increases the absolute contribution margin and FLH of the electrolyser. Additionally, the risk from varying RE generation is mitigated. The electrolyser benefits more from increasing green hydrogen prices than in the case of high simultaneity. The associated emissions, however, increase with a low simultaneity. Therefore, the simultaneity obligation delivers on its original goal at the cost of reduced incentives for the electrolyser operator.

To the best of our knowledge, the paper at hand is the first to evaluate the dependence of an electrolyser's profitability 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 presents the model framework and the numerical assumptions for the case study, and section 3 shows the results. In section 4, we discuss the implications of our findings. We conclude our paper in section 5.

2. Methodology

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 1 summarises the key components of our methodological approach.

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. 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 includes the risk of

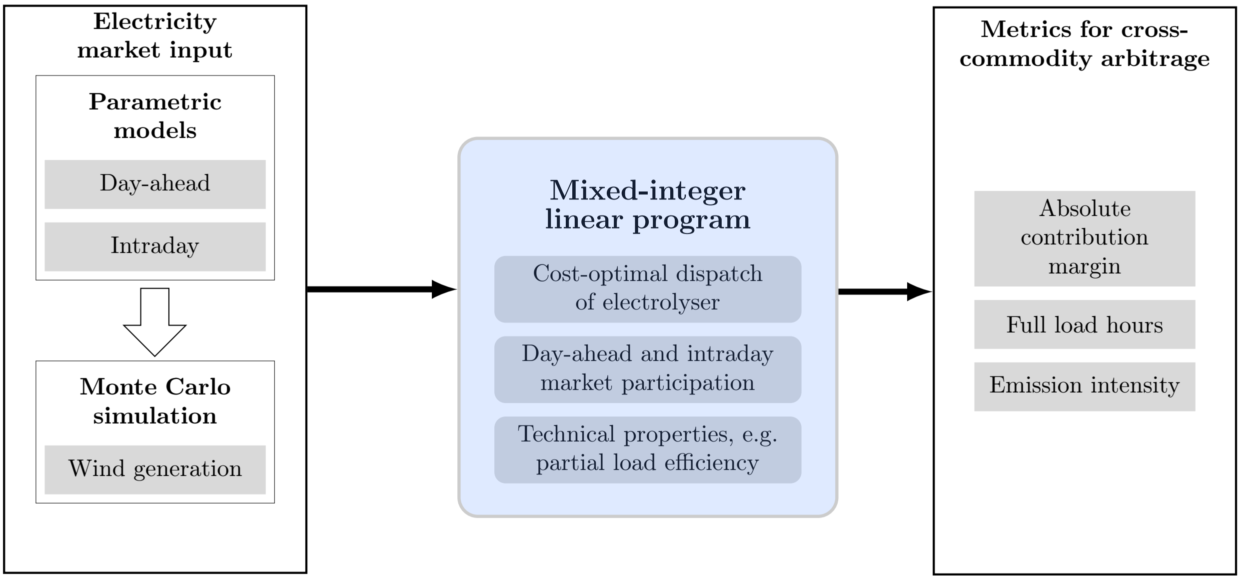

Figure 1: Methodological approach consisting of a mixed-integer linear program, stochastic price time series generation, and metrics for cross-commodity arbitrage.

uncertain wind generation. The models are applied in a case study for one year. Finally, we evaluate the case study with metrics for the viability and CO_2 intensity of the corresponding hydrogen production.

2.1. Mixed-integer linear program of electrolyser operation

The economic viability of an electrolyser depends on its variable cost, fixed operative and maintenance (O&M) 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. Fixed O&M and investment costs are not considered in the short-term dispatch decision and, therefore, excluded from the dispatch model.

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.

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

The revenue is calculated in equation (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 output of the plant depends on its 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 in equation (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 obligation of RE and hydrogen production. The simultaneity is determined by 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 power production within the same period. If $\gamma > 1$, the electrolyser can virtually shift the RE production from one period to another. 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 given simultaneity interval 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 defines the capacity ratio of the RE plant and the electrolyser. For the first periods ($t \leq \gamma$), the equation (6) is modified such that the latest period valid for balancing equals one. The 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.

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

While the model formulation simplifies some technical characteristics and does not consider all the electrolyser's business opportunities (e.g., frequency control), it has the advantage of low computation time. This allows solving the deterministic model for multiple realisations to follow a stochastic approach.

2.2. Synthetic electricity price time series

In a power system with a high share of RE, hydrogen production would rely on renewable primary energy carriers, such as wind and solar. The availability of these resources is intermittent, observable in electricity systems with high penetration of wind and solar generation. Since volatility 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 the other 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 implicitly (Elberg and Hagspiel, 2015). 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 on the 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 A.2. With these time series and the parametric models, we compute synthetic electricity price time series.

2.3. Evaluation metrics

The results are analysed for the short-run profitability of an electrolyser. First, the electrolyser's annual contribution margin is evaluated, which is defined as the sum of hourly cost minus hourly revenues (see equation 1). Second, FLH for one year are determined: $FLH = \frac{Q}{Cap}$ (de Groot et al., 2017). Third, the CO_2 emission intensity of hydrogen is determined. Hydrogen production with electricity does not create inherent CO_2 emissions. However, depending on the emission factor for electricity, the indirect carbon emissions of grid-connected electrolysers can be larger than zero, whereby either marginal or average emission factors can be used (Huber et al., 2021). The drawback of average grid emission factors is their high inaccuracy due to a high temporal variation in actual emission factors for electricity. Further, the merit-order principle of power plant dispatch is neglected, as 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 specific CO_2 emissions of hydrogen requires 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 with two different measures to estimate a range of emission intensity of hydrogen.

We assume that a simultaneity of a quarter-hour, which is the lowest temporal unit of electricity balancing purposes in the EU, has an emission factor of 0 gCO_2/kWh_{el}, thus represents a perfect balancing of RE and hydrogen production[1]. Consequently, each (positive) deviation of the quarter-hourly power consumption from the RE generation leads to additional electricity demand, which is not supplied by the RE generator and must be balanced by the grid, where it increases the power production from the marginal power plant. The indirectly induced emissions are calculated by multiplying the total grid-power consumption with the emission factor for electricity in each period. We apply two emission factors for electricity: (i) The marginal emission factor (MEF) equals the specific emission factor of the marginal power plant, which sets the market price on the intraday market based on its marginal cost (Fleschutz et al., 2021). Hence, the marginal emission factor is determined by mapping the quarter-hourly intraday price with the marginal costs of different power plants. The yearly average grid emission factor (YAEF) is defined as the total emissions of the power sector divided by total electricity production and is constant throughout the year. Finally, the hydrogen emission

[1]While even in the case of quarter-hourly simultaneity the actual emissions induced by the electrolyser might be higher, the assumption enables comparability with higher simultaneity values.

intensity is calculated by dividing the total absolute CO_2 emissions (in kg) by the total absolute quantity of hydrogen produced (in kg).

Within the analysis, the obtained distributions of these three metrics are compared regarding their arithmetic mean value and their coefficient of variation (CoV). The CoV, or relative standard deviation, sets the standard deviation in relation to the mean of the distribution and measures the dispersion of a data set. The comparison focuses on general structures represented by relative changes to the base case rather than on absolute estimations.

2.4. Case study design

We simulate the model with historical German electricity market data 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.[2] Generation, forecast, and realised electricity demand 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. The simulation is run in quarter-hourly resolution for one year and 1000 samples of wind generation with accordingly derived electricity prices. The resulting parametric models for the electricity prices are shown in Appendix A.1.

The parameterisation of the electrolyser is based on literature data and summarised in Table 2. From the linearisation of the input-output function, we receive a minimum efficiency at full load of 52 %, maximum efficiency at part-load of 61 %, and average efficiency of 54 %. The efficiency values include peripheral equipment and refer to the higher heating value of hydrogen (Kopp et al., 2017). The assumed parameters only represent an exemplary electrolyser. In practice, technical and economic characteristics are extensive and depend on multiple factors. Various review articles and studies published data on techno-economic electrolyser characteristics (see e.g., Thema et al. (2019); Saba et al. (2018); Götz et al. (2016)). Consequently, the simulation results depend on the parameterisation of the electrolyser. Based on current German regulation, we assume electricity price surcharges of 2.39 €/MWh.[3]

The initial exogenous hydrogen price is set to 3 €/kg in the base case and varied in a subsequent sensitivity (see section 3.5). Currently, hydrogen is not traded on transparent and liquid markets. Instead, over-the-counter trades and bilateral contracts between producers and consumers organise volumes and prices. Here, we assume a selling price for green hydrogen as an indicator of the willingness to pay. The price is not varied over time since hydrogen can be stored, stabilising the hydrogen prices (Green et al., 2011). The green

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

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

characteristic is varied by changing the simultaneity obligation since it affects the renewable characteristic of the power supply.

A reference list mapping MEF with electricity prices is derived from Fleschutz et al. (2021), which covers the German power system for the year of 2019. Hence, the MEF used from the study coincide with the data input for the regression analysis spatially and temporally for the most recent year. A day-ahead price of 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 gCO_2/kWh_{el} for prices below that threshold. As YAEF of Germany we assume 408 gCO_2/kWh_{el} (Umweltbundesamt, 2021).

Parameter	Value	Unit
Production capacity	1	MW_{el}
Ramping gradient	100	% $\frac{cap}{15\ min}$
Minimum load	20	% of cap
CAPEX	800	$\frac{e}{kW_{el}}$
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)).

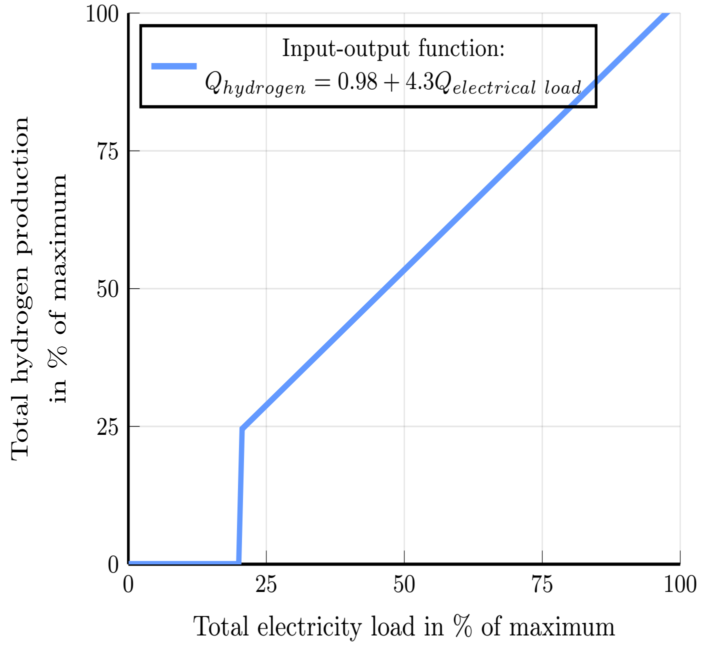

Figure 2: Electrolyser input-output-function (own assumption based on Kopp et al. (2017).

3. Results

We obtain results for the electrolyser dispatch within the defined case study. First, we present the time series of randomly drawn wind generation realisations and corresponding electricity prices. For a base case, we show then the distribution of the absolute contribution margin and the FLH of a standardised electrolyser. Fourth, we assess the impact of a simultaneity obligation on both the dispatch level and the yearly dispatch risk. Fifth, the interdependence between a simultaneity obligation and the green hydrogen selling price are analysed. Lastly, we highlight the effect on the CO_2 emission intensity of hydrogen.

3.1. Price time series

Based on the Markov chain, we generate 1000 samples of a yearly wind generation time series in quarter-hourly resolution. Combined with the parameterised day-ahead and intraday models, these wind generation samples obtain 1000 samples of quarter-hourly intraday prices and hourly day-ahead prices. Figure 3 illustrates the sampled range of these three time series. The two price time series diagrams show the upper and the lower limit of the sampled price duration curves, i.e. the sorted quarter-hourly electricity prices.[4] The lower diagram shows the range of the corresponding wind capacity factors.[5]

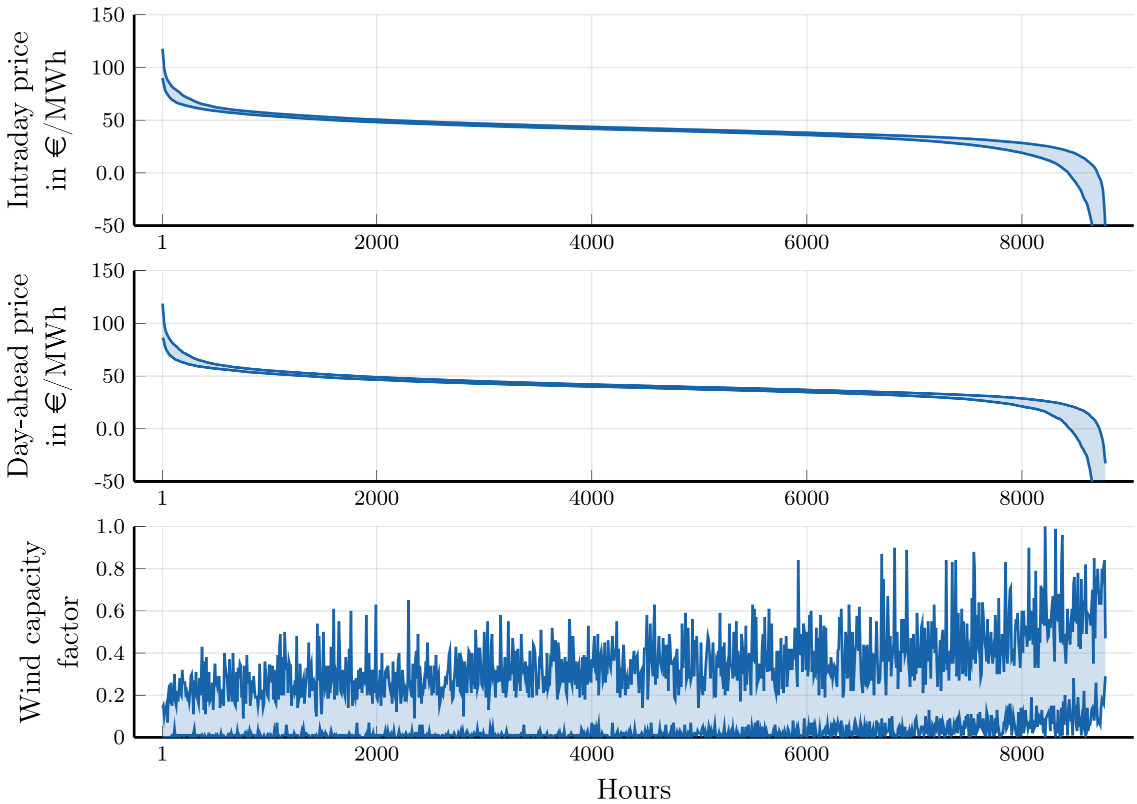

Figure 3: The price duration curve of the intraday prices, the day-ahead prices, and the wind generation. The upper and lower limit of the sampled price duration curves are shown, and the wind generation's corresponding upper and lower limits.

The middle illustration in Figure 3 shows the dispersion of the day-ahead price duration curves. Towards the lower and the upper end, the price dispersion increases. In the middle part, however, the dispersion

[4] The electricity prices are first sorted, and then the maximum and minimum of each sorted hour are shown in the respective diagram. They span the range of price duration curves within the total sample.

[5] The single samples are, first, sorted according to the order of the day-ahead price duration curves. Then the maximum and minimum of the wind capacity factor are shown in the diagram, also spanning the range of possible wind capacity factor realisations given the corresponding day-ahead price.

is comparably low. The parametric models in A.8 represent the merit-order of the electricity market. The resulting price responses are stronger for particular high and low residual loads so that the differences between the samples in these periods lead to high dispersion in the price duration curves. Differences in the less extreme residuals translate into comparably low price differences. The illustrations show a negative correlation between the wind capacity factor and the electricity prices, indicating the merit-order effect of RE generation. Additionally, the figure shows that the dispersion of the wind capacity factor is higher in hours with low electricity prices. Electricity prices are mostly affected by wind generation when its feed-in is comparably high, resulting in a lower residual demand[6] (Sensfuß et al., 2008). This leads to lower prices when wind capacity factors are high and consequently to a higher dispersion of electricity prices depending on the variation of wind generation. The intraday price duration curve is quite similar to the day-ahead price duration curve as the source of variation is the wind generation forecast errors. These result in mediate deviations from the day-ahead price.

Table 2: Descriptive statistics of the samples wind generation and the regressed price time series.

Unit	Yearly capacity factor wind	Price day-ahead €/MWh	Price intraday €/MWh	Value factor day-ahead €/MWh	Value factor intraday €/MWh
Min	0.14	-149	-180	25	24
Max	0.18	106	106	37	37
Mean	0.16	40	41	33	33
StD	0.007	15	16	2	2

Table 2 shows the descriptive statistics of the simulated time series and the resulting value factors for the wind generation profile. The mean yearly capacity factor overall samples is 0.16, which equals approximately 1400 FLH. The minimum overall sampled years is 0.14 and the corresponding maximum is 0.18. The mean over all hourly electricity prices is 40 €/MWh for the day-ahead market and 21 €/MWh for the quarter-hourly intraday market, respectively. The mean of electricity price maxima deviates only in the decimals between day-ahead and intraday, while the mean of minima is 31 €/MWh lower on the intraday market. The value factors confirm the negative correlation between wind generation and electricity prices. With 33 €/MWh, it is lower than the mean average electricity price. The upper bound for the electricity market price, at which the electrolyser is dispatched, depends on the green hydrogen selling price, which translates into an electricity break-even price through the plant-specific efficiency.

3.2. Dispatch of a grid-connected electrolyser

A green hydrogen selling price of 3 €/kg and no simultaneity obligation define the base case. To understand the effects of higher simultaneity on the electrolyser's dispatch, we first present the two main

[6]Defined as total electricity demand less RE feed-in, which is the demand being supplied by conventional power plants.

characteristics of this dispatch for the base case. First, we show the total profitability of the electrolyser's dispatch indicated by the distribution of the absolute contribution margin (upper histogram in Figure 4). Consecutively, we show the electrolyser's production rate indicated by the distribution of FLH (lower histogram in Figure 4).

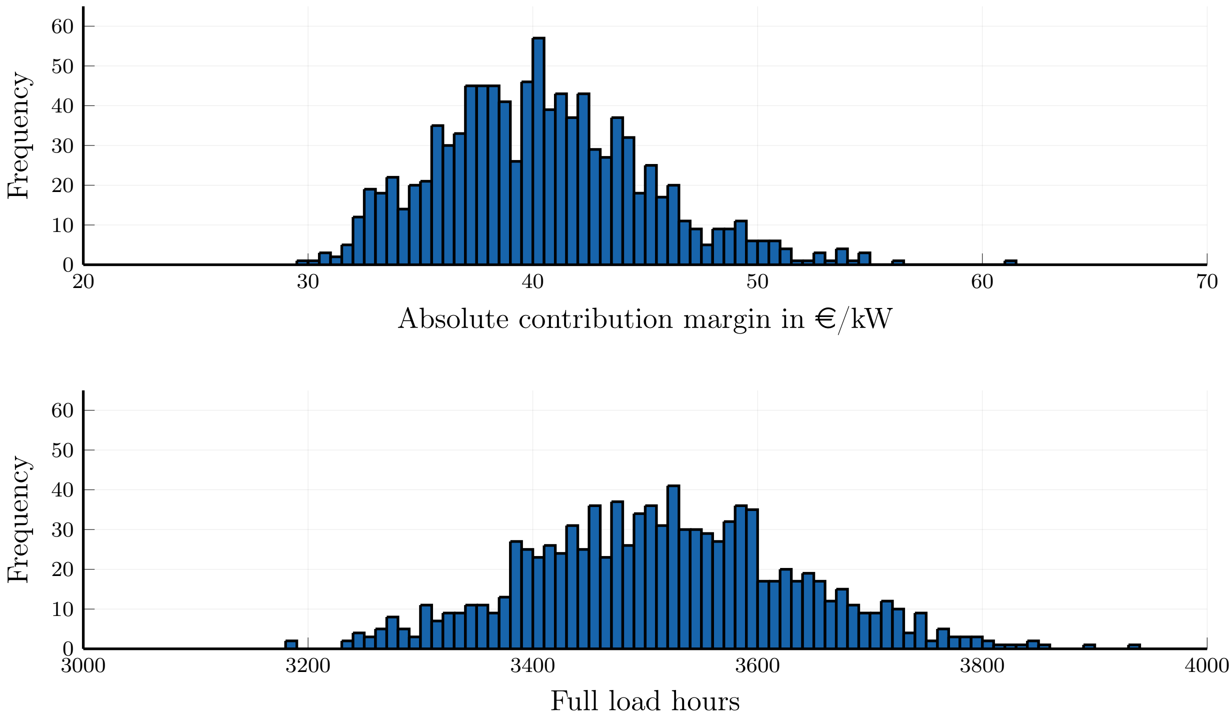

Figure 4: The distribution of the absolute contribution margin (top) and the full load hours (bottom).

The absolute contribution margin for a year ranges from 30 €/kW in the worst case to 61 €/kW in the best case. In the mean, the electrolyser would generate a margin of 40 €/kW with a standard deviation of 5 €/kW. This results in a CoV of 0.12. The distribution is slightly right-skewed since it is higher concentrated for low margins than for high margins. The underlying wind generation distribution initially causes the right skewness. Without simultaneity, it only affects the absolute contribution margin through electricity prices. The FLH show a symmetrical distribution with a mean of 3517 hours and a standard deviation of 115 hours. Since, in this case, the electrolyser is not constraint by a wind generation profile, the FLH are determined by the hydrogen price, its corresponding electricity break-even price, and the electricity price duration curve on the market.

The mean CO_2 emission intensities are 31.9 $kgCO_2/kg_{H2}$ when applying the MEF and 30.1 $kgCO_2/kg_{H2}$ using the YAEF. The break-even price defines the range of possible marginal power plants. From the mean FLH of 3517, we can derive the finding that the electrolyser mostly operates in periods where electricity prices are either set by generation technologies with close-to-zero marginal costs, e.g., nuclear, RE or by baseload generation technologies, such as lignite power plants. Whereas the former has an emission factor for electricity of zero, the latter has the highest emission factor of all generation technologies. Consequently, the electrolyser either withdraws power from the grid when the MEF is particularly high or low, which leads on average to a similar emission intensity of hydrogen compared to the YAEF.

3.3. Simultaneity effect on the yearly dispatch level

Starting from the base case with a hydrogen selling price of 3 €/kg and no simultaneity, we first introduce a simultaneity of one year and increase it up to an interval of 15 minutes. The discrete intervals are *None*, 1 a, 12 hours, 8 hours, 1 hour, and 15 minutes. The hydrogen price remains constant. The results are normalised with regard to the base case. The normalised means of the contribution margin and FLH are shown in Table 3.

Table 3: Relative changes to the base case of the mean values of contribution margin and FLH in the simultaneity sensitivity.

	Simultaneity					
in % of Base case	None	1a	12h	8h	1h	15min
Mean						
Contribution margin	100	98	78	75	71	67
Full load hours	100	78	57	54	51	47

The results show that the mean contribution margin decreases with an increasing simultaneity. Without any simultaneity, the absolute mean contribution margin results in a value of 40 €/kW. Compared to this, the contribution margin with simultaneity of 15 minutes is 33 % lower. The introduction of a yearly simultaneity would decrease the contribution margin by 2 %. As a power consumer, the electrolyser profits during low-price periods as hydrogen can be sold at a fixed price. If no simultaneity obligation is in place, implicitly, all hydrogen produced by the electrolyser is considered green, which can be interpreted as the virtual generation of the green electricity characteristic. The electrolyser runs in all periods with an electricity price lower than the break-even price. The introduction of simultaneity ties the electrolyser production to the wind generation profile. The electricity consumption is only considered green within a specific time interval and after its generation by the wind generator. Therefore, already yearly simultaneity prevents the virtual generation of green electricity. Implicitly, low simultaneity allows the electrolyser to store the green characteristic of the electricity since it can generate the green characteristic in high price periods and consume it in low price periods. The shorter the time interval, the lower the storage capability of the electrolyser, and, hence, the lower the profit from this storage. Therefore, the case of a 15 minute simultaneity does not allow the electrolyser to store the green characteristic and marks the lowest contribution margin with 67 % of the base case. The case of yearly simultaneity, on the other hand, implies the largest virtual storage resulting in a contribution margin of 98 % of the base case. Thus, the potential value of virtual green electricity storage is significant and can make up to one-third of the electrolyser's contribution margin.

The potential value of virtual storage also becomes apparent in the FLH. Without simultaneity, the mean FLH sum up to 3517 hours, corresponding to a capacity factor of 40 %. The introduction of yearly simultaneity reduces the FLH by 22 %. Compared to the base case *None*, where the break-even price alone determines the FLH, the total yearly production of the wind generator limits the FLH in case of yearly simultaneity. The 22 % difference marks the additional potential generation by a larger wind generation capacity for the electrolyser. However, the 22 % FLH only account for 2 % of contribution margin. The electrolyser mainly loses less profitable hydrogen generation at high electricity prices. Increasing the simultaneity further to 15 minutes results in a FLH reduction of 53 % compared to the base case. Compared to the case of yearly simultaneity, the reduction is 31 % points with regard to the base case. Analogously to the contribution margin, the allowance to virtually store the green electricity characteristic can make up to 40 % of the electrolyser's hydrogen production.

3.4. Simultaneity effect on the yearly dispatch dispersion

The sensitivity of the contribution margin and FLH dispersion to a varying simultaneity is shown in Table 4. The results are normalised with regard to the base case.

Table 4: Relative changes to the base case of the coefficient of variation (CoV) of contribution margin and FLH in the simultaneity sensitivity.

	Simultaneity					
in % of Base case	None	1a	12h	8h	1h	15min
Coefficient of variation						
Contribution margin	100	104	126	130	135	143
Full load hours	100	141	170	178	189	216

The absolute CoV of the contribution margin in the base case results in 0.12 and increases with higher simultaneity. Introducing yearly simultaneity increases the CoV by 4 %. Reducing the interval to 15 minutes results in a CoV increase of 43 %. The allowance to store the green characteristic of the electricity generation increases the robustness of the electrolyser towards varying yearly wind generation. In the case of yearly simultaneity, the dispersion between years with different wind generation realisations is defined by the lower end of the price duration curve (see Figure 3) since the electrolyser can shift all of its power consumption into the lowest price periods. For simultaneity of 15 minutes, the dispersion between the yearly wind generation profiles mainly determines the dispersion of the contribution margin as the electrolyser cannot shift its consumption. The results indicate that the dispersion between the yearly RE generation is higher than the dispersion between the yearly electricity prices, which finds support in the illustration of the time series in Figure 3. The variation within the wind capacity factor is higher than the variation within the electricity

Table 5: Absolute values of the mean contribution margin and the FLH at a hydrogen selling price of 3 €/kg

	Unit	None	1a	15min
Mean contribution margin	€/kW	40.4	39.4	27.2
Mean FLH	h	3516	2740	1641

prices (see Table 2). Lower simultaneity decouples the contribution margin from the risk associated with the economic value of the wind generation profile. This risk can account for one-third of the total risk from yearly varying wind generation.

The CoV of FLH increases with a higher simultaneity. In the case of yearly simultaneity, the CoV is 41 % higher than in the base case (with an absolute value of 0.03). For simultaneity of 15 minutes, the CoV is 216 % of the base case's CoV. The simultaneity appears to have a more significant effect on hydrogen production risk than on the contribution margin risk. As already observed for the mean of the FLH, introducing a simultaneity obligation significantly increases the CoV. Constraining the total yearly FLH to the wind generation limits the FLH of the electrolyser, shifting the main dispatched hours to the high dispersion area at the low prices of the duration curve. Therefore, the dispersion increases significantly with the introduction of yearly simultaneity. Increasing the simultaneity further towards the 15 minutes interval increases the importance of the dispersion within the low electricity prices and the importance of the dispersion between the yearly wind generation profiles since only wind generation within periods with prices below the break-even price lead to hydrogen production. Hence, the hydrogen production risk resulting from the wind energy profile makes one-third of the total risk.

3.5. Interdependence of the simultaneity and the green hydrogen selling price

The hydrogen price is a decisive factor for the electrolyser's viability, but it is generally unknown in the absence of a liquid hydrogen market. Therefore, a sensitivity is applied to the price. We simulate the electrolyser dispatch model for a green hydrogen price of 2, 2.5, 3, 3.5, 4 and 4.5 €/kg. Three cases will be presented: starting from the base case (i) without a simultaneity obligation, the sensitivity is additionally applied on the simultaneity of (ii) one year and (iii) 15 minutes. In Table 5 the absolute values for the mean contribution margin and the FLH are summarised. Within each case, the relative deviation from a reference price of 3 €/kg is computed for the mean and the CoV of the contribution margin and the FLH. Figure 5 illustrates the results.

The diagram on the top left in Figure 5 illustrates the sensitivity of the contribution margin's mean on the hydrogen price for three simultaneity cases. Regardless of the simultaneity, the contribution margin increases with a rising hydrogen price. The exact gradient of this increase diverges between the different simultaneity obligations. In the absence of simultaneity, hydrogen production is profitable for all periods with an electricity price below the break-even price. Therefore, increasing the hydrogen price increases both

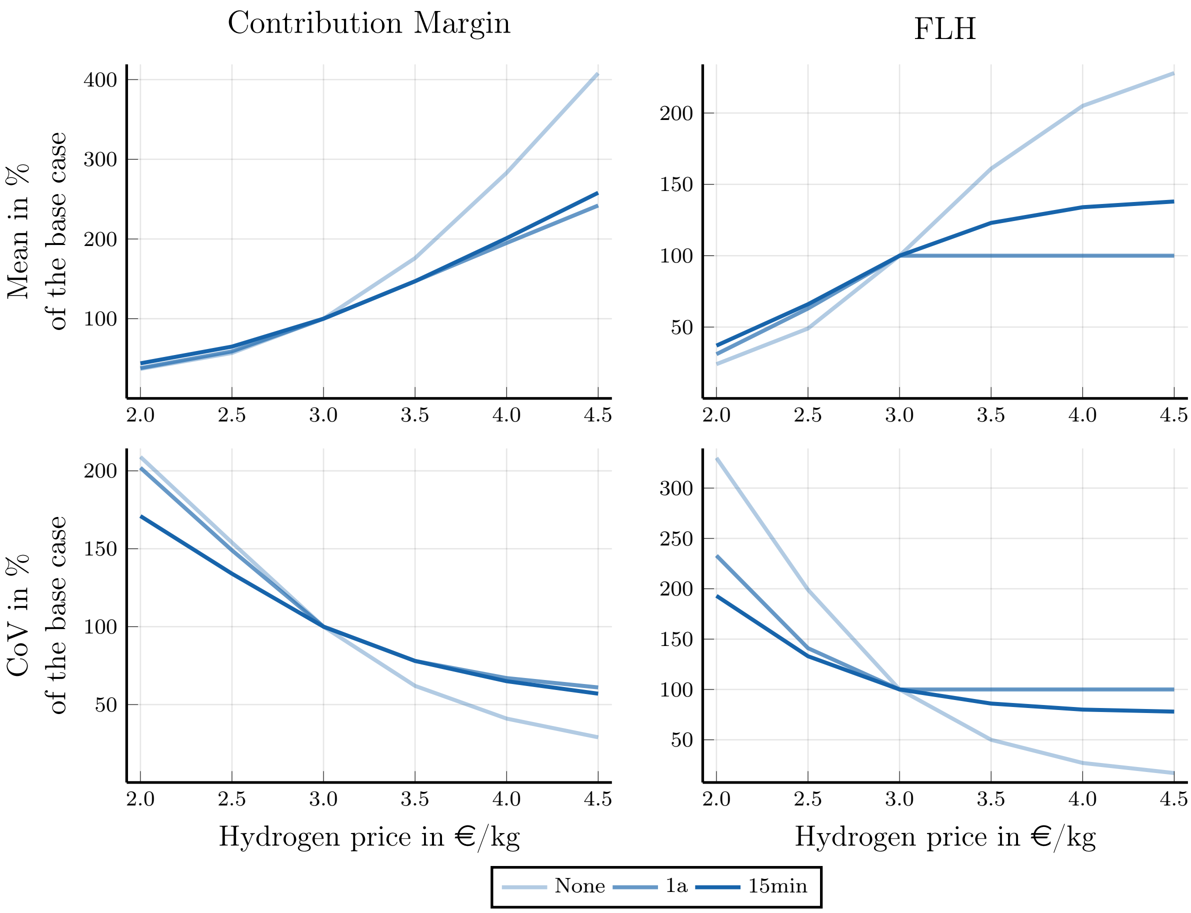

Figure 5: Relative changes to the base case of 3 €/kg of the mean (upper) and the CoV (lower) of the contribution margin (left) and the FLH (right) in %.

the contribution margin for the already profitable periods and makes additional periods profitable. This twofold effect results in a convex contribution margin increase. Increasing the hydrogen price by 1.5 €/kg increases the contribution margin by 408 %. Introducing yearly simultaneity, the electrolyser only profits from storing the green characteristic. As the FLH of the wind generation are limited, there is a saturation level of the contribution margin increase through higher production. Therefore, once the break-even price is sufficiently high to capture as many periods as FLH provided by the wind generator, the contribution margin increases linearly. At a hydrogen price of 4.5 €/kg, the contribution margin is 242 % of the contribution margin at 3 €/kg. With quarter-hourly simultaneity, the electrolyser is also prevented from benefiting from green characteristic storage. This significantly reduces the mean contribution margin of the base case (see Table 5). However, the relative increase of the mean contribution margin is higher than with yearly simultaneity. With lower simultaneity and thus larger green characteristic storage, the electrolyser reaches already for lower hydrogen prices the saturation level of the wind generation FLH. In the absence of the storage allowance, the electrolyser reaches the saturation level not until higher hydrogen prices.

The relative changes of the FLH, and thus the total output of the electrolyser, are shown in the top right diagram of Figure 5. The change in FLH is s-shaped, with a first convex increase, followed by a concave increase with a decreasing growth rate in FLH at a hydrogen price of more than 3.5 €/kg. The convex and concave course becomes most visible in the case of no simultaneity. For example, the FLH can be more than doubled (plus 105 %) when increasing the price from the base case (3 €/kg) to 4 €/kg, whereas it only increases by 67 % points when changing from 3.5 to 4.5 €/kg. This shape can be explained with the price duration curves in Figure 3. If the price is varied at a level such that the electricity break-even price lies in the flat part of the price duration curve, the number of operating periods is very sensitive to a change in the hydrogen price. If it is varied at the upper or lower end of the price duration curve with few prices at one level, the FLH are less sensitive to hydrogen price changes. Increasing the FLH is possible to a limited extent since electricity prices eventually reach the left tail of the price duration curve with soaring prices in a few hours of the year. Introducing yearly simultaneity adds a FLH saturation level based on the wind generation capacity factor. With the given assumptions, the maximum FLH are reached with a price of 3 €/kg. A further increase in the price enables the electrolyser to be dispatched in more periods from an economic perspective (as shown in the first case without simultaneity). However, total wind energy production, i.e., virtual green electricity storage, is fully utilised. For simultaneity of 15 minutes, the FLH only increase with a higher hydrogen price when periods exist which have spare wind generation and electricity market prices above the electricity break-even price. Hence, the extent to which a higher hydrogen price increases the FLH in this situation strongly depends on the correlation between wind generation and electricity prices. Here, at a price of 3 €/kg, there are still periods with wind power generation but without hydrogen production, which allow increasing the electrolyser's output at higher hydrogen prices.

The diagram on the bottom left in Figure 5 shows the contribution margin's CoV sensitivity on the hydrogen price. The relative CoV's resulting course shows a convex decrease for each line. In the case, *None* without simultaneity, the CoV for a hydrogen price of 2.0 €/kg is 209 % of the CoV in the base case. For a hydrogen price of 4.5 €/kg, however, it decreases to 29 %. An increasing hydrogen price decreases the contribution margin's CoV in two ways. First, it defines the break-even price and, hence, the FLH and average short-term costs. A higher hydrogen selling price moves the break-even price along the flat part in the middle of the price duration curves. Here, the variation between the sampled years is low compared to the variation at the end of the price duration curve. With a higher hydrogen price, the share of the periods with prices, which vary little between the samples, on the total periods grows. This leads to a relative reduction of the CoV. Second, a higher hydrogen price increases the absolute contribution margin per kg produced hydrogen. As the variation in the case without simultaneity only originates from the varying electricity prices, an increase of the revenue per kg decreases the relative impact of the production costs and thus the

CoV of the contribution margin. In the case of yearly simultaneity, the electrolyser's dispatch is constrained by the total FLH of the wind generator. Therefore, it already reaches for lower hydrogen prices a saturation level of CoV reduction than without simultaneity. For a hydrogen price of 4.5 €/kg, the relative CoV is 61 %. The electrolyser only benefits from the first effect, i.e. the slight variation in the flat part of the price duration curve, until it reaches the wind generator's FLH. The second effect of increasing revenue compared to the cost variation remains. This also holds for the case of high simultaneity of 15 minutes. Although the FLH of the wind generator are exhausted for higher hydrogen prices (leading to a slightly higher CoV reduction rate), the CoV is mainly reduced due to the second effect for higher hydrogen prices. However, for lower hydrogen prices, the relative CoV increase is lower than for no and yearly simultaneity. While for no and yearly simultaneity, the price variation at the lower end of the price duration curve determines the CoV, the CoV in case of high simultaneity is determined by the wind generation value factor. Due to the negative correlation between electricity prices and wind generation, the wind value factor has a lower dispersion than the electricity prices (see Table 2.

The FLH CoV's sensitivity on the hydrogen price is shown in the bottom right diagram of Figure 5. All curves show a convex decrease. The decrease rate is the highest for the case of no simultaneity, falling from 330 % of the base case's CoV for a hydrogen price of 2.0 €/kg to 17 % for a 4.5 €/kg. Again two effects play a role in this decrease. First, the variation in the flat part of the price duration curve is lower than at its ends, resulting in a low CoV for break-even prices in this part. Second, for high hydrogen prices, the FLH of the electrolyser are comparably high. Variation between the samples of a few hours only increases the CoV slightly. Therefore, the curve is convex in its reduction. Introducing yearly simultaneity adds a saturation level in the form of the wind generator's FLH. Therefore, once this saturation level is reached at 3 €/kg, the CoV does not change anymore. For lower hydrogen prices, the relative increase of the CoV is lower than in the case of no simultaneity. For 3 €/kg, the electrolyser is already constrained by the FLH of the wind generator so that a further decrease of the hydrogen price is relatively a lower effect than in the case of no simultaneity. Given a quarter-hourly simultaneity, the CoV reaches the saturation level for higher hydrogen prices than under yearly simultaneity since the electrolyser cannot shift its dispatch into periods with sufficiently low electricity prices. Analogously to the contribution margin, the CoV of the FLH increases with a lower rate for decreasing hydrogen prices.

3.6. Emission intensity

The additional value from storing the green characteristic of electricity comes with a potential fading of the actual greenness of the associated electricity consumption. The additionally induced electricity generation of conventional power plants to serve the electrolyser's demand may increase indirect emissions. This issue does not only apply to the operation of electrolysers but also for other power consumers (e.g., battery electric vehicles (Nansai et al., 2002), demand-side response (Fleschutz et al., 2021)). The relative emission intensity of hydrogen to the base case is determined for each considered simultaneity. Furthermore, the mean emission intensities are determined for varying hydrogen prices along with the simultaneity of *None*, one year, and 15 minutes.

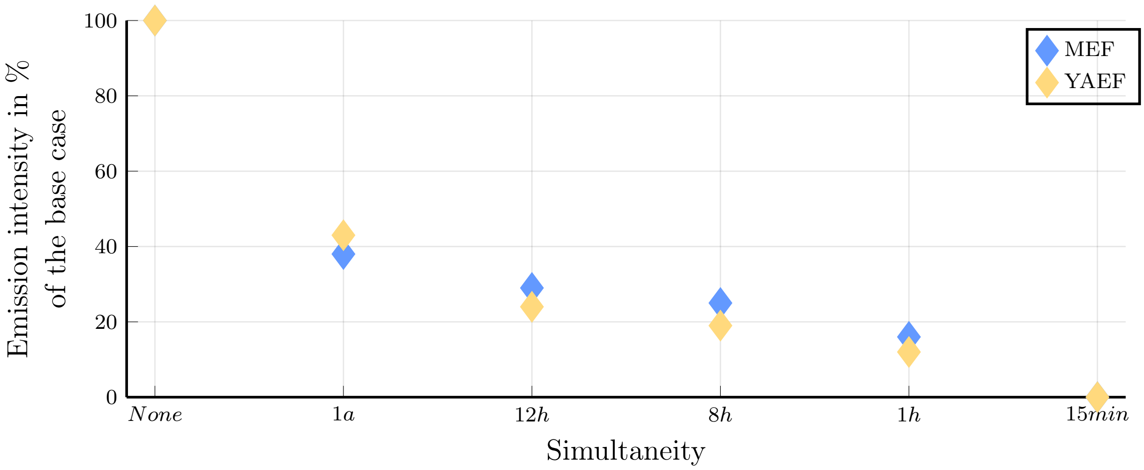

Figure 6: The hydrogen emission intensity in % indicated by the MEF and the YAEF depending on the simultaneity.

In Figure 6, the mean CO_2 emission intensity of hydrogen for the simultaneity sensitivity is visualised. Starting from the case of no simultaneity, the relative average emission intensity is shown for each considered simultaneity. The case without simultaneity has the highest relative emission intensity since the grid fully balances the electricity consumption. Following the assumptions in section 2, a quarter-hourly simultaneity corresponds to perfect balancing of RE and hydrogen generation and induces no additional indirect CO_2 emissions. Hence, the emission intensity of hydrogen is 100 % lower compared to the base case. The trend indicates a reduction in emission intensity with increasing simultaneity in between these cases. The largest drop occurs when a simultaneity obligation is imposed, i.e., moving from no simultaneity towards yearly simultaneity. Here, the emission intensity decreases by more than 50 % for both the YAEF and the MEF.

Moving downwards from yearly to lower simultaneity in discrete steps, the emission intensity further decreases, but the effect weakens. Note that the time intervals between the simultaneity cases differ, and the change in emission intensity must be regarded relatively to the respective interval. The difference between 12 hourly and 8 hourly simultaneity is only 6 % points for the MEF and 5 % points for the YAEF, respectively. With simultaneity of 8 hours, the emission intensity of hydrogen reduces by more than two-thirds compared to the base case (*None*). A substantial decrease can be noticed when moving from hourly to quarter-hourly simultaneity, i.e. to perfect balancing, where the emission intensity decreases by more than 10 % points in both cases, although the step is the lowest on a time-scale. When comparing the results for yearly with quarter-hourly simultaneity, the relative emission intensity deviates by a value of 38 % points. The effect of the simultaneity on the emission intensity appears to be very similar for both emission factors for electricity. This implies that higher simultaneity reduces the share of electricity balanced from the grid, but the average mean emission factor for electricity does not change significantly.

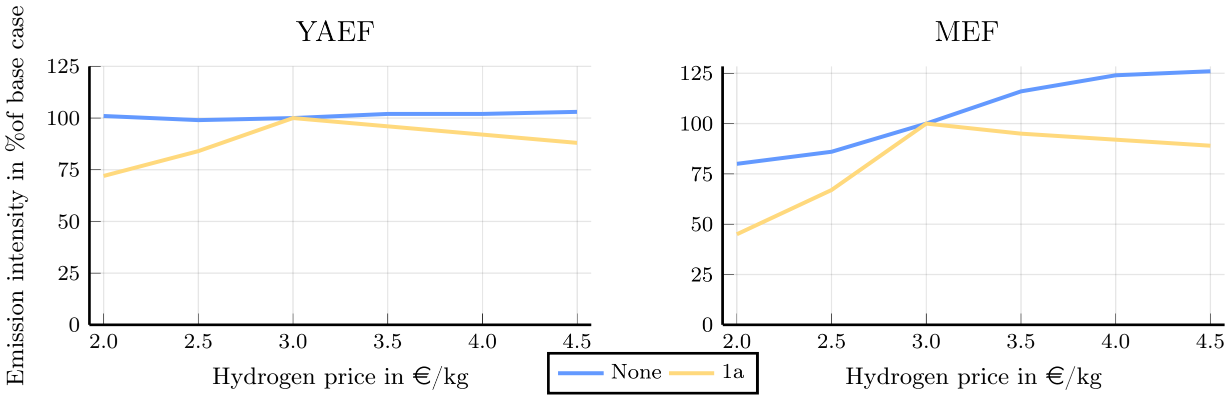

Figure 7: The relative hydrogen emission intensity to the base case (3 €/kg) indicated by the MEF (left) and the YAEF (right) for the hydrogen price sensitivity.

Besides the simultaneity, the hydrogen price can affect the emission intensity of hydrogen since it changes the electricity break-even price and, therefore, the possible range of marginal power plants. The charts in Figure 7 show the relative emission intensity of hydrogen depending on the price for yearly and no simultaneity when applying the MEF (left chart) and the YAEF (right chart). The emission intensity for quarter-hourly simultaneity is not displayed, as it does not change with the price and always equals zero in absolute terms.

Applying the YAEF, the emission intensity does not change when no simultaneity obligation is in place since both the emission factor for electricity and the power balanced by the grid are constant overall prices. With yearly simultaneity, the emission intensity depends on the share of electricity which exceeds the generation from the RE sources and is balanced by the grid. The mean emission intensity of hydrogen decreases when the hydrogen price is reduced from the base case price of 3 €/kg. Low electricity prices usually occur when residual demand is low and when RE feed-in is high. With increasing residual demand, the electricity market price rises and the share of electricity, which is balanced by the grid, increases. Consequently, a comparably low selling price for green hydrogen limits the electrolyser to produce only in periods with low electricity prices and accordingly high feed-in from the RE generator, which means that less power must be balanced by the grid lowering the emission intensity of hydrogen. However, a comparably higher price with yearly simultaneity also decreases the emission intensity. Here, the emission intensity hits its maximum at 3 €/kg and slightly decreases afterwards. While the mean FLH reach the maximum with a price of 3 €/kg and do not increase with higher prices (see section 3.5), the considered part-load efficiency allows the electrolyser to increase the total output by using the same amount of electricity. In a small range of electricity benchmark prices, it is economically efficient for the electrolyser to operate in partial load to increase efficiency and accept a lower output. With a higher hydrogen price, this price range increases and the operating periods with partial load shift towards higher electricity market prices. As a result, the total output of the electrolyser increases while the consumed power remains constant, which leads to a slightly lower emission intensity of hydrogen with a higher hydrogen price.

Applying the MEF, the emission intensity of hydrogen increases with the hydrogen price when no simultaneity obligation is in place. The change is s-shaped, meaning more minor deviations from the base case with a price of 3 €/kg lead to more substantial emission effects than higher deviations. The MEF depends–besides the rate of power balanced by the grid–on the electricity market price. With higher prices, the electrolyser can also be dispatched during mid and peak load periods, which can be seen by the increased FLH with a higher price (see section 3.5). In these periods, coal and gas-fired power plants are often marginal suppliers, which have lower emission factors in comparison to lignite power plants. Hence, the increase in indirect emissions is slowed down. With yearly simultaneity and applying the MEF, the trend of the mean emission intensity is similar to the YAEF, but the decrease at lower prices is stronger when applying the MEF. Since the MEF depends on both the share of power balanced the grid and on the electricity market price, the effect of the marginal power plant affects the emission intensity in two ways: the MEF is lower at a comparably lower hydrogen price, and the power supply from the RE generator is higher since it often produces in periods with low electricity prices. On the other hand, the emission intensity decreases with a higher hydrogen price and yearly simultaneity. The effect is analogue to the YAEF reasoned by the increase in output with the same FLH, but the emission intensity is affected by the electricity price and the change in total output.

4. Discussion

This paper presents the dispatch decision of an electrolyser, highlighting the impact of a simultaneity obligation in the presence of risk from varying wind generation. The simultaneity can be interpreted as an allowance to store the green characteristic of the RE plant's electricity generation. In the case study, we show that this allowance improves the business case of an electrolyser in three ways. First, the storage capability adds economic value to the dispatch of the electrolyser. The electrolyser benefits from time arbitrage, shifting the green characteristic from high-price to low-price periods. This arbitrage increases the electrolyser's contribution margin. Second, the virtual storage also mitigates the RE generation risk, both price and quantity. Third, the contribution margin's sensitivity to green hydrogen price changes is higher. The electrolyser benefits directly from higher hydrogen prices as it can shift it to periods in which the electricity price is sufficiently low. These three aspects also hold for the hydrogen production quantity. However, the marginal value of one unit of additional virtual storage, in terms of a longer simultaneity interval, depends on the correlation between RE generation and electricity price. The time interval expansions within the first 8 h after electricity generation have a higher marginal effect than the time interval expansions after several weeks. That is because the virtual storage is particularly valuable when the electrolyser profits from periods with a negative correlation between wind generation and electricity price (also determined by solar photovoltaics (PV) generation and the load pattern). These shifts within a day provide a high marginal value per simultaneity interval. The factors driving these electricity market prices will change. For instance, prices for natural gas and CO_2 emission allowances are expected to significantly increase in Europe, while the number of periods with excess RE generation will increase. The price duration curve may become steeper with higher prices at the left and more periods with low prices at the right end, tightening the middle part (Ruhnau, 2021). Electrolysers can benefit from this development, since profits increase with the number of periods with electricity prices below the break-even price.

The main goal of a simultaneity obligation is the prevention of additional indirect CO_2 emissions from subsidised grid-connected electrolysis. During the hydrogen market ramp-up, the electricity supply mix has still significant shares of conventional power generation translating, if not constrained, into a high emission intensity of hydrogen. Our results have shown that the simultaneity, indeed, affects through the electrolyser dispatch its emissions. With higher simultaneity, the emission intensity of hydrogen decreases compared to the absence of a simultaneity obligation. From a system perspective, it can be argued that the German power sector under consideration in the case study is part of the EU ETS, where the total emission budget is theoretically limited. However, in practice the market stability reserve (MSR) softens this limit. Increased emissions from electricity generation for the purpose of hydrogen production can lead to lower cancellation of emission allowances in the short-term or even higher emission allowance auction volumes. To which extent the emission demand from hydrogen production would displace emission demand or rather increase overall emissions, remains ambiguous. The dynamic design of the EU ETS prevents a definite determination of the emission effect from hydrogen production (Schmidt, 2020; Bocklet et al., 2019). Generally, regulation may tend to tailor different green characteristic definitions to each emission mitigation option. However, maintaining these various definitions in parallel may induce distortions not only between green and non-green technologies but also within green technologies. Regardless of the indirect effect on emissions in the short-term, the simultaneity obligation may have a due date controlling an electrolyser's dispatch given substantial investment subsidies, since with higher shares of RE in the electricity supply mix, a simultaneity obligation becomes obsolete.

Given the dependence of the short-term dispatch decision on the RE generation risk and the simultaneity, it is of interest for an investor how these conditions affect the long-term profitability. The profits must cover the annuity and other fixed costs in order to make the electrolyser investment viable. Taking the assumptions of the case study from section 2.4 on investment cost, depreciation time, and interest rate, we can derive an annuity (including fixed cost) of 119 €/kW. Comparing the fixed and annuity costs to the mean contribution margin from the base case of 40 €/kW, the investment would prove as unprofitable with a financing gap of approximately 80 €/kW. Given a standard deviation of 5 €/kW, even in the more advantageous cases, the electrolyser can not cover its long-term cost. The relative risk of the contribution margin–expressed as CoV in section 3–increases with the simultaneity by up to 43 % when changing from *None* to quarter-hourly simultaneity. However, this increase in the risk is relatively low when comparing the absolute financing gap of 80 €/kW with the standard deviation of 5 €/kW. As a result, an investor would prioritise lowering the fixed and annuity costs than reducing the risk resulting from short-term dispatch decisions. Note that this calculation only holds for representative years regarding RE feed-in and electricity market prices based on the historical observations. In the mid-term, the change of the price-duration curve allows electrolysers to enhance their economic viability. In the long-term, the expansion of electrolyser capacity and flexible consumers, in general, may lead to more elastic demand and hence to increased competition for low electricity prices, which could dampen the profitability of electrolysers (see e.g., Lynch et al. (2019); Ruhnau (2021); Roach and Meeus (2020)).

5. Conclusions

The hydrogen market ramp-up requires large-scale investments in electricity-based hydrogen production. With substantial subsidies, policymakers aim to set sufficient incentives for investors to realise these investments. As the reduction of CO_2 remains the crucial overall goal, introducing specific rules for the dispatch along with the investment subsidies is discussed to limit associated emissions from an electrolyser's energy consumption. One discussed criterion is a simultaneity obligation between renewable energy (RE) generation and electrolyser production. While its purpose would be to limit the emissions, the measure significantly affects the dispatch of an electrolyser and may distort the investment incentive.

With our research, we contribute to understanding these distortions that policymakers may consider when designing dispatch criteria for electricity-based hydrogen production. We set up a model framework that allows us to assessing a grid-connected electrolyser dispatch taking into account the risk from varying RE generation. The variation of RE is captured by a Monte Carlo Markov chain simulation for wind generation forecast and forecast errors. Subsequently, two regression models for the intraday and day-ahead markets are calibrated with historical data from the German spot markets to calculate synthetic electricity spot market price time series. We introduce simultaneity to the dispatch model and evaluate its structural impact on the distribution of the electrolyser's contribution margin, full load hours, and associated emissions within a case study in the German electricity market context.

In the short term, we show that the introduction of a simultaneity obligation delivers on its original goal in reducing the associated CO_2 emissions from electricity consumption. On the other hand, an absence of simultaneity comes with several significant benefits for the operator of an electrolyser: the contribution margin and production rate increase while the risk from RE generation decreases. Policymakers may decide whether these additional benefits from the virtual storage of the green characteristic shall be granted to the electrolyser or they accept the weakened investment incentive to assure low associated CO_2 emissions.

This research focuses on the effect of simultaneity on the dispatch of an electrolyser in the presence of risk stemming from varying wind generation. Further research on more complex portfolio constellations may improve the understanding of electrolyser dispatch, e.g., by including solar photovoltaics and offshore wind as potential sources of RE or by considering the opportunity of selling the electricity at the wholesale market. This could shed some light on the valuation of RE sources and may also contribute to the understanding on price formations of power purchase agreements. Another decisive determinant of an electrolyser's viability is the hydrogen price of a prospective hydrogen market, which is currently largely unknown. It is therefore of particular interest to further assess the willingness to pay of green hydrogen and to better understand the price formation mechanisms of prospective hydrogen markets. A third direction of further research is an analysis of the interaction between investment and dispatch regulatory interventions during the hydrogen market ramp-up.

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Appendix A.

Appendix A.1. Regression Results

The regression results for the day-ahead market are illustrated in Figure A.8. Based on the data for the years 2015-2019, a function is fitted to each month of the year.

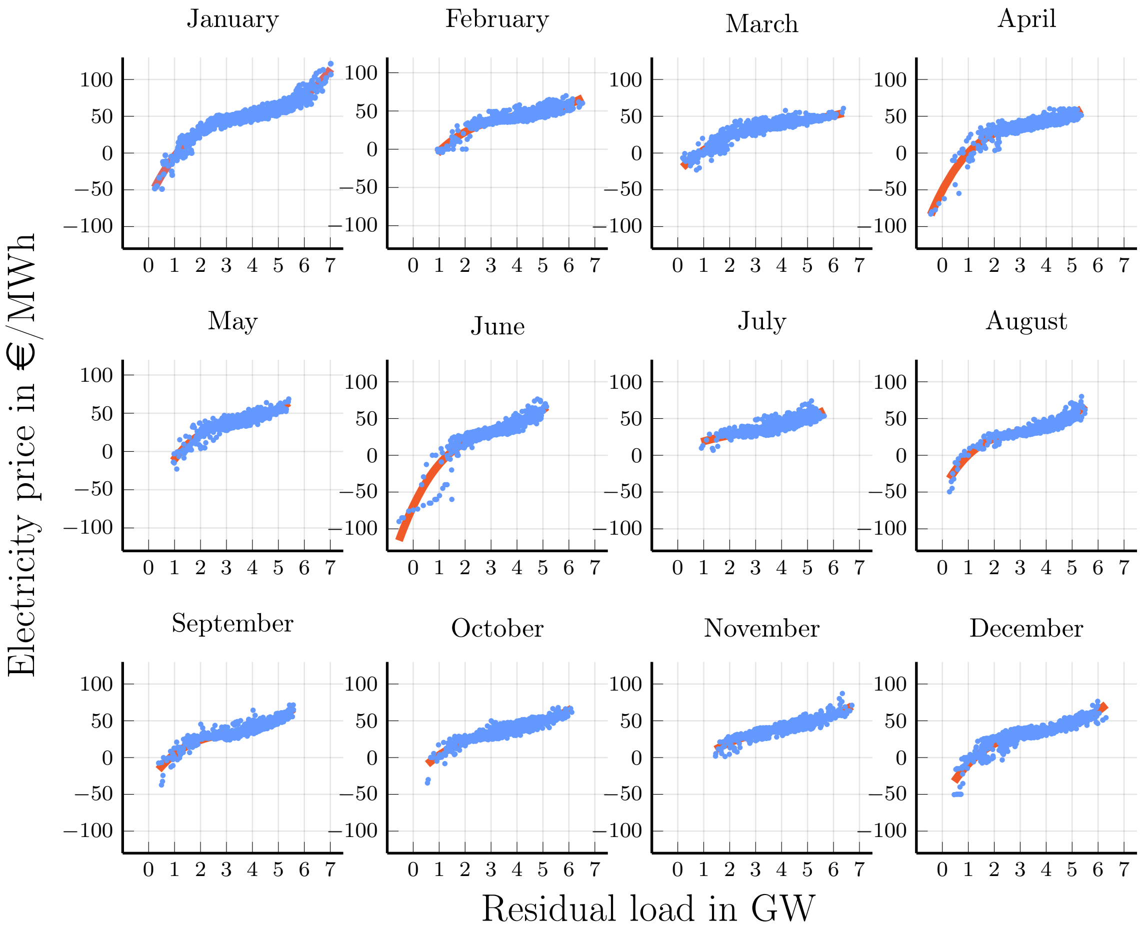

Figure A.8: Regression results for the day-ahead market.

Analogously, the intraday market prices are regressed on the day-ahead market prices and the wind generation forecast error. Table A.6 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.6: 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 not 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. We obtain a cumulative distribution function of possible following states for every state.

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 3 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 3.

Appendix A.3. Annuity

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

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

Appendix A.4. Annotation

Table A.7: 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	Green hydrogen selling price
p^{DA}	EUR/MWh_{el}	Day-ahead price
p^{ID}	EUR/MWh_{el}	Intraday price
p	EUR/MWh_{el}	Electricity price
δ	-	Time scaling
cap	MW_{el}	Electrolyser capacity
α	EUR/MWh_{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_{el}	Residual load
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_{el}	Load
B	-	Binary variable to determine whether plant is switched on/off
FE	-	Forecast error