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Exploring the scale-up of a green hydrogen industry: An agent-based modeling approach

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ABSTRACT

Given the significant investments needed to build a green hydrogen industry, energy modeling must move beyond techno-economic optimization to include stakeholders as active drivers of the transition. This paper uses agent-based modeling to analyze investment dynamics in the coupled electricity, hydrogen, and electrolyzer markets of Germany. The model incorporates heterogeneous investors with varying expectations about future market conditions. We examine how different investment strategies and willingness to pay for green hydrogen affect the development of electrolyzer manufacturing and green hydrogen supply. Results show that deep levels of power sector decarbonization and 40 GW of installed electrolyzer capacity by 2050 are possible, but require strategic, short-term loss-incurring investment decisions and a substantial premium for green hydrogen over grey hydrogen. However, even in our best-case scenario, Germany's 2030 electrolyzer targets remain out of reach, as decarbonization is confined to the power sector during the 2020s.

1. Introduction

Green hydrogen is expected to play a leading role in the decarbonization of many industry sectors because it can act as a versatile energy carrier, with no direct CO_2 emissions during its production [1–3]. As a result, the green hydrogen and electrolyzer markets are expected to shift from a niche market with limited impact on the electricity system to a global mass market with major electricity demand [4]. The European Commission, for example, has set a target to produce up to 333 TWh of green hydrogen and expects that up to 25 % of electricity produced from renewables will be used for electrolysis by 2050 [5].

The strict definition of green hydrogen – as hydrogen produced through electrolysis using electricity from renewable sources – increases the demand for additional renewables to cover the additional electricity demand. The liberalized nature of the electricity, green hydrogen, and electrolyzer markets, with multiple individual players, results in a complex system [6], as these actors are now expected to play a significant role in the transition to a mass market. As private actors are expected to build this industry, their investment decisions come under increased scrutiny.

The market for green hydrogen is currently relatively small but is anticipated to grow substantially. The exact global demand for green hydrogen is a much-researched topic [7], with estimates for future global demand varying widely from 120 to 660 Mt by 2050 [8]. In comparison, current global demand for all types of hydrogen stands at 95 Mt [9]. However, global installed electrolyzer capacity in 2024 was estimated to be only 5.2 GW [10]. To meet future demand, an expansion of installed electrolyzer capacity by several orders of magnitude is necessary [1,11]. However, the expansion of green hydrogen production capacity is hindered by financial uncertainties, particularly the willingness to pay for green hydrogen [12]. Yet, this aspect remains less explored, as current studies predominantly focus on the costs of producing and supplying green hydrogen [13].

Global installed electrolyzer manufacturing capacity in 2023 was only 14 GW/year, with actual production reaching just 1 GW [14]. While there have been announcements of investments in new manufacturing capacities, these may not be sufficient, and the realization of such investments is not guaranteed [9]. The real challenge lies in the coordination of building renewables, electrolyzers and electrolyzer factories to ensure these three sectors are in sync as delayed capacity

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expansion could lead to bottlenecks in the supply chain [15].

1.1. Modelling markets

Modeling the development of green hydrogen, electrolyzer, and electricity markets can help identify the limitations of scaling an industry from a niche to a mass market, as well as the conditions required for its long-term profitability. Such a model may also uncover hidden dynamics and potential feedback loops. While numerous studies have focused on the transformation of the electricity market (e.g., Refs. [16–18]), an increasing number of models now incorporate green hydrogen production and consumption (e.g., Refs. [19–23]). However, few studies address the deployment of electrolyzers and their manufacturing capacities. For example, Odenweller et al. compare past scale-ups in other industries (e.g., smartphones, internet hosts) to project the potential growth of electrolyzer availability [24].

Energy system optimization models are commonly used to analyze the development of the electricity system (e.g., Refs. [25–27]). These large-scale models provide cost-optimal pathways for the energy transition and for power plant operations. However, they assume an idealized world to answer the question of "what should be" [28]. Typically, such models are based on a single central actor with perfect knowledge and absolute control to implement the cost-optimal solution. In contrast, today's electricity market has evolved into a competitive, multi-actor environment. Similarly, the green hydrogen and electrolyzer markets have never been operated as centralized, state-run systems. To fully understand their dynamics and development, it is necessary to account for heterogeneous actors with limited information and rationality, and their investment decisions.

In addition to optimization models, equilibrium models are frequently used to study the energy transition (e.g., Refs. [29–32]). These models use algebraic and/or differential equations to represent system dynamics [33]. For more complex problems that cannot be captured by formal equilibrium frameworks, simulation models serve as an alternative approach [34].

While these and other neoclassical models – assuming rational economic behavior – have provided valuable insights at the macroeconomic level [35], they fail to reflect the reality of heterogeneous and only partially rational decision-makers [36]. Assumptions such as perfect foresight can be overly strict and lead to under estimate challenges and restrict possible scenarios [37,38]. Alternative tools are needed to better capture bounded rationality [28].

1.2. An agent-based approach to green hydrogen industry investments

Agent-based models (ABMs) are well-suited for modeling complex adaptive systems such as the electricity, green hydrogen, and electrolyzer sectors [39]. They are effective in representing adaptive, heterogeneous actors – such as investors – whose behavior contributes to emergent system dynamics [39]. ABMs can offer new insights into the development of these interlinked sectors that may not be captured by more traditional energy system modeling approaches.

Several ABM studies have focused on electricity system transformations, investigating both consumer behavior (e.g., Refs. [40–42]) and investor behavior (e.g., Refs. [43–47]). In the green hydrogen sector, ABMs have been applied to broader energy systems (e.g., Ref. [44]) as well as to the development of specific hydrogen technologies, such as fuel cell vehicles (e.g., Ref. [48]).

To the best of our knowledge and the reviewed literature, no study to date has modeled the simultaneous development of all three sectors – electricity, green hydrogen, and electrolyzers – using an ABM approach. Existing ABM studies have primarily focused on the electricity sector, and only few have explored the coupling between the electricity and green hydrogen sectors. Consequently, there is a gap in understanding the role of heterogeneous actors with bounded rationality in the integrated development of the electricity, green hydrogen, and electrolyzer sectors.

This study aims to model the transformation toward a decarbonized economy by focusing on the scale-up of the green hydrogen industry. To this end, we develop an ABM that simulates the dynamics of the electricity, hydrogen, and electrolyzer sectors in a representative Western country, such as Germany. The model incorporates the investment decisions of heterogeneous actors and is designed to be transferable to countries with similar characteristics. Furthermore, we vary the willingness to pay for green hydrogen to address the knowledge gap concerning how hydrogen pricing affects technological and market development.

Based on these considerations, the following research questions arise.

- **R1:** What are the fundamental processes driving the scale-up of the green hydrogen industry?
- **R2:** How do different investment strategies impact the scale-up?
- **R3:** How significant is the willingness to pay a premium for green hydrogen?

The remainder of the paper is structured as follows: Section 2 outlines the initial set of assumptions underlying our ABM. Section 3 describes the conceptualization of the model. In Section 4, we present our experiments and results, followed by a discussion in Section 5. The paper concludes with a brief reflection on our modeling approach.

2. Investment decisions in coupled sectors of electricity, green hydrogen and electrolyzers

Our model examines the role of investors in renewables, electrolyzers and their manufacturing capacities and their investment decisions, analyzing how these decisions influence the dynamics of the electricity, green hydrogen, and electrolyzer industries. To avoid overparameterization, we aim to keep the model as simple as possible. We propose the following initial assumptions as a reasonable starting point for an investor-focused agent-based model.

I. Future prices for electricity, green hydrogen, and electrolyzers, as well as technology learning rates for electrolyzers, are unknown to investors.
II. Investors base their investment decisions on individual expectations about the future.
III. Past performance of investors influences their investment capacity and outlook.
IV. New investors may enter the market.

Given the political goal to achieve carbon neutrality in the power sector, we incorporate the following additional assumptions.

V. Investors in the electricity sector invest exclusively in renewable power generation assets.

However, residual demand is covered by gas turbines that are not explicitly modeled.

VI. Renewable power generation has a seasonally variable supply, and no seasonal storage solution is available besides green hydrogen.
VII. The electricity market operates as an energy-only market.

For green hydrogen production, we assume.

VIII. Green hydrogen is produced exclusively from renewable electricity in excess of non-electrolytic electricity demand.

For the electrolyzer market, we assume.

IX. The electrolyzer market operates as a modified single sealed-bid auction where prices are not transparent and negotiations determine the closing price.

Finally, to reflect on the early stage of these industries.

X. The green hydrogen and electrolyzer markets are emerging markets where strategic investment decisions are possible.

2.1. Investors' heterogeneous views on the future and their investment decisions

The first assumption (Assumption I) includes factors such as the pace of electrolyzer capacity expansion, future costs, performance of assets, and future market price developments – all of which are unknown. Given that these variables influence company performance and that actors have different preferences, it is logical that they also hold varied expectations about the future (Assumption II). These differences reflect varying risk thresholds and company strategies among investors, resulting in heterogeneous views on market development. Variations in both internal and external factors lead to heterogeneous capital return requirements across different investors [46].

Typically, investment opportunities are evaluated by analyzing common metrics, such as the net present value (NPV) [49]. In our model, we extend this approach by using the ratio of net present value to investment costs.

2.1.1. Influence of past performance on new investment decisions

Given that investors have heterogeneous outlooks on the future, their investment decisions vary accordingly. As markets evolve, these differences lead to varying income and cost structures among investors, which in turn affect their performance. The overall performance of an investor's assets influences their outlook on future developments (Assumption III).

Since Western electricity markets have been liberalized, new companies have entered the market, e.g. there are nearly 480 electricity providers in Germany [50]. Similarly, the green hydrogen and electrolyzer markets, as emerging sectors, are also expected to attract new entrants [1] (Assumption IV).

2.2. Assets

2.2.1. Renewable power generation assets

Most European electricity systems currently rely on a mix of renewable and thermal power plants. However, as the transition to a carbon-free economy progresses, renewable assets have become the primary focus for new capacity expansion (Assumption V). While wind and solar power provide CO_2 emissions-free electricity and have low operational costs, their power output is intermittent. Despite this variability, no large-scale seasonal storage solutions are currently operated to address these fluctuations [51]. Green hydrogen may take this role (Assumption VI). Other storage technologies, such as pumped-storage power plants have limited potential for further expansion [52]. Battery storage primarily provide short-term capabilities [53]. This makes it challenging to predict their impact on the availability of excess electricity. Nevertheless, these technologies do have an effect, and in practice, they influence the development of electrolyzers. However, since our model focuses specifically on electrolyzers, we have not included these storage technologies.

2.2.2. Electrolyzers

Although electrolyzers are not a new technology, their use for green hydrogen production is not yet widespread. Various types of electrolyzers exist at different technology readiness levels: Alkaline, proton exchange membrane and solid oxide electrolyzers [54]. However, no single type has yet emerged as the dominant technology, and it remains uncertain which one will lead the market in the future.

Currently, electrolyzers involve high capital costs, although these are expected to decrease over time. In fact, historical data show that costs have already declined in the past [54]. This reduction is partly attributed to learning effects, with learning rates of 9–21 % reported for electrolyzers in the literature [55]. However, interviews with stakeholders from the electrolyzer industry reveal that the actual costs for turn-key electrolyzers – including the stack, balance of plant, and project engineering, etc. – are often underreported and higher than suggested in the current literature [11].

2.2.3. Factories for electrolyzer manufacturing

Many new electrolyzer manufacturing factories are being announced, but it remains uncertain how many of these will actually be built [56,57]. Currently, the global production capacity for electrolyzers is 25 GW/year [10]. Today's announced projects indicate, that the size of new production capacities is increasing rapidly (cf. Refs. [10,58–60]).

2.3. Markets

Assumptions VII to IX address the functioning of different markets, including the green hydrogen market. While the hydrogen and electrolyzer markets are liberalized by nature, pro-market reforms that liberalized the electricity sector in OECD and non-OECD countries took place in the 1980s and 1990s [61]. These liberalized markets are designed to foster competition among actors [62].

2.3.1. Electricity market as an energy only market

In energy-only markets, power generators offer varying quantities of electricity at different prices, ranked from the lowest to the highest marginal costs (Assumption VII). The market-clearing price is set so that the marginal cost of the most expensive producer required to meet demand determines the price. These costs include fuel and variable operation and maintenance expenditure (OPEX) but exclude capital expenditures (CAPEX). Power producers earn their margin from the difference between their individual marginal costs and the market-clearing price, which is necessary to recoup their investment.

2.3.2. Green hydrogen market and willingness to pay

Green hydrogen is chemically identical to hydrogen from other sources and is therefore not a distinct product but rather a substitute for hydrogen produced from fossil fuels. As such, it competes with fossil-based hydrogen. However, there may be a premium that customers are willing to pay for green energy like green hydrogen, driven by commitment to decarbonize or other factors [63].

By definition, green hydrogen is produced using exclusively renewable electricity [2]. If an electrolyzer is using grid electricity, it can produce green hydrogen only if the entire electricity supply is sourced from 100 % renewable sources; in other words, the electrolyzer should only operate when all demand is met by renewable sources and thus use only excess electricity (Assumption VIII).

2.3.3. Electrolyzer market as a modified sealed-bid auction

Electrolyzers are industrial machines designed and procured as projects rather than consumer products; they are business-to-business products [64]. Consequently, there is no transparent market [11]. For this reason, we assume that interested buyers must request bids from manufacturers to purchase an electrolyzer (Assumption IX). The simple auction-based approach was developed with the aim of keeping the model logic as straightforward and transparent as possible.

2.3.4. Strategic investment decisions in emerging markets

The markets for green hydrogen and electrolyzers are projected to experience substantial growth [10] (Assumption X). In emerging markets like the green hydrogen market, firms often adopt aggressive growth strategies [65]. These strategies typically involve prolonged periods of negative net cash flow, which has become the dominant approach for companies in emerging markets [66]. Similarly, recent investments in the electrolysis business have been made without expectation of direct profitability [11,67].

One reason for these types of investment strategies is the anticipation of a first-mover advantage. In addition to considerations of market share and survival [68], first-mover advantages can be represented by a positive present value for a company due to early market entry [69]. Key potential factors for first-mover advantages include: (1) technological leadership, (2) preemptive acquisition of assets, and (3) buyer switching costs [70]. Technological leadership can emerge through mechanisms like ‘experience curves’, which can reduce average production costs [71]. Preemptive acquisition involves securing resources, geographical locations, production plants, or equipment [72]. Finally, consumer switching costs create a barrier for consumers to switch to a functionally identical product from another producer, thereby granting the producer a degree of market power [73].

3. Conceptualization

The ABM used in this study was developed following the 10-step framework proposed by van Dam et al. [74] and implemented in the NetLogo software environment [75]. NetLogo has been used for complex simulation models due to its highly efficient built-in primitives and its compatibility with High Performance Computing clusters [76].

Building on our understanding of the three markets and investor behavior, we developed the conceptual framework of our model, shown in Fig. 1.

The model concept is based on a literature review and semi-structured interviews [11]. The model has been verified and validated through recording, single- and multi-agent testing, and agent tracking [74]. Model results were analyzed using Python. This section only provides a brief overview of the model conceptualization. A fully detailed description and a list of symbols is available in Appendix A. Flow charts showing the model logic can be found in Appendix B. The model, as well as the description, is open source and is published on github.com.[1]

3.1. Investors

Three types of investors exist in our model: power producers (PP) in the electricity market, hydrogen producers (HP) in the green hydrogen market, and electrolyzer manufacturers (EM) in the electrolyzer market. Each investor evaluates investment opportunities using the ratio of the Net Present Value *NPV* to investment costs of an asset *I* in comparison to their investment threshold φ as their key metric, i.e.:

$$\frac{NPV}{I} \geq \varphi \qquad \text{Eq. 1}$$

A global minimum threshold for this threshold is established for each market, representing the lowest acceptable ratio for all investors. However, investors' heterogeneous expectations about the future are reflected in agent-specific thresholds for the NPV-to-investment-cost ratio. The rate at which this investment threshold changes differs among investors.

New investors may also enter the market. Whenever all existing investors in a market have invested in new assets, a new investor may enter that market.

Investor adaptivity is modeled through the dynamic adjustment of their individual thresholds based on past performance. Each investor's threshold increases or decreases according to their profitability, representing the investor's expectation for the future. This adjustment occurs once per year, prior to new investment decisions.

[1] https://github.com/b-jesse/HIM.

3.2. Assets

There are three types of assets in the model: renewables (R), electrolyzers (E), and factories for manufacturing electrolyzers (F). Each asset class has distinct characteristics (cf. Table 2). Renewables exhibit variable daily capacity factors. For simplicity, renewables are assumed to be a mix of photovoltaic, onshore wind, and offshore wind. Capacity of newly added renewables increases with each investment until reaching a maximum.

Electrolyzers are initialized with equal capacity and efficiency. Similar to renewable assets, the capacity of electrolyzers increases with each investment.

Manufacturing capacities for electrolyzers represent the third asset type. These are initialized with equal capacity and production costs. The capacity of new factories increases with each new investment up to a maximum value. Production costs at which a new factory produces electrolyzers c_E are calculated based on the cumulative electrolyzers capacity produced $A_{E,cum}$:

$$c_E(t) = c_{E,0}\left(\frac{A_{E,cum}(t)}{A_{E,0}}\right)^{\frac{\log(\lambda)}{\log(2)}} \qquad \text{Eq. 2}$$

Where $c_{E,0}$ is the production costs in year zero (i.e. the start of the simulation), $A_{E,0}$ the capacity of electrolyzers in year zero, and λ is the learning rate for electrolyzers.

3.3. Electricity market

The electricity market in our model operates on two time scales: daily and yearly actions. On a daily basis, renewable assets produce electricity to meet non-electrolytic electricity demand and if possible, demand by electrolyzers. This paper primarily focuses on the impact of the green hydrogen industry, so we assume that the non-electrolytic electricity demand – covering all other sectors – remains constant year over year, including its daily variations (cf. Refs. [77,78]). This demand is assumed to be inelastic and must be met at all times.

If the installed renewable assets cannot generate sufficient electricity, the deficit is supplied by gas turbines, which are not modeled as assets in this study. In this case the electricity price is determined by the merit order and thus by the gas turbines (cf. Eq. (3)). When renewable assets generate more electricity than the non-electrolytic demand, surplus electricity is considered excess electricity and can be used for green hydrogen production.

If excess electricity is insufficient to fully supply all installed electrolyzers, hydrogen producers pay for the electricity (cf. Eq. (4)). Given that all hydrogen producers compete for a limited amount of excess electricity, their willingness to pay for electricity is equal to the price of hydrogen multiplied by the efficiency of the electrolyzers. This represents the maximum willingness to pay at which they do not incur any losses from the sale of hydrogen produced using that electricity. If there is more excess electricity than the electrolyzers can utilize, the electricity price is set to zero (cf. Eq. (5)).

The electricity price in the three different cases is as follows:

$$p_{elc}(t) = \frac{p_{gas}}{\eta_{GT}} \; for \; P_{R,all,mmax}(t) < D_{elc}(t) \qquad \text{Eq. 3}$$

$$p_{elc}(t) = w_{elc}(t) \; for \; D_{elc}(t) \leq P_{R,all,max}(t) \leq D_{elc}(t) + \sum A_E \qquad \text{Eq. 4}$$

$$p_{elc}(t) = 0 \; for \; P_{R,allmmax}(t) > D_{elc}(t) + \sum A_E \qquad \text{Eq. 5}$$

Where p_{elc} is the electricity price, p_{gas} the natural gas price, η_{GT} the efficiency of gas turbines, $P_{R,all,max}$ the current maximum output of renewables, D_{elc} the non-electrolytic electricity demand, w_{elc} the willingness to pay for electricity by hydrogen producers, and A_E the installed capacity of electrolyzers. Fig. 2 depicts the electricity price

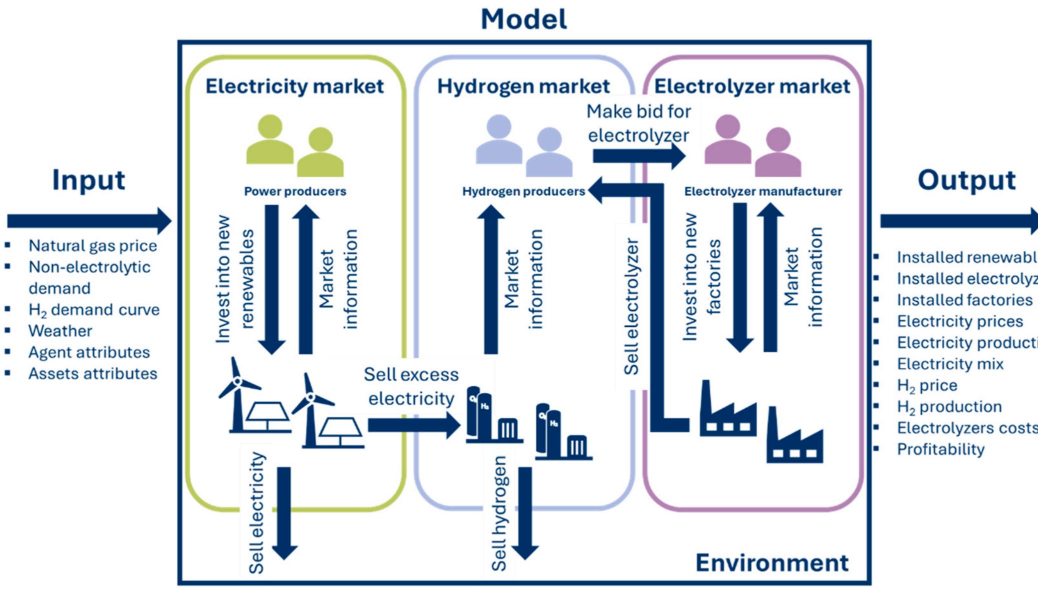

Fig. 1. Model description. Power producers and electrolyzers manufacturer invest in assets based on market information and their heterogeneous investment threshold. Hydrogen producers invest in assets based on market information, asset availability and their heterogeneous investment threshold.

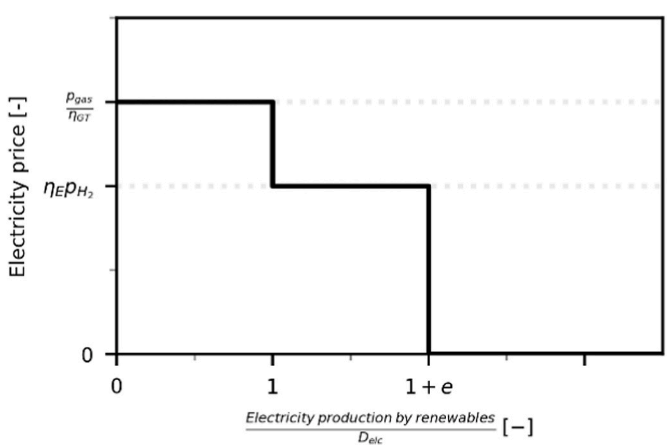

Fig. 2. Electricity price depending on the ratio of maximum output by renewables and non-electrolytic electricity demand. Where e is the total normalized electrolyzer capacity, defined as the ratio of total installed electrolyzer capacity and the maximum output of renewables.

depending on the ratio of maximum output of renewables and non-electrolytic electricity demand.

On the yearly scale, at the end of each year, power producers calculate their profitability for that year and adjust their outlook accordingly by updating their investment threshold. Each power producer performs an NPV analysis for a potential new renewable asset and invests if the NPV is greater than their individual threshold. If all existing power producers decide to invest in a new asset, a new power producer enters the market, initializing with one renewable asset.

3.4. Hydrogen market

The hydrogen market operates on both daily and yearly timescales. Electrolyzers produce hydrogen daily, which is immediately sold as we do not consider hydrogen storage. The price of green hydrogen is updated annually at the beginning of each year. This price is determined based on the cumulative hydrogen production from the previous year and the corresponding willingness to pay for that quantity. The demand curve in the best-case scenario, with varying willingness to pay for green hydrogen, is shown in Fig. 3.

The curve reflects varying levels of willingness to pay for green hydrogen across different industries, depending on expected policies and subsidies (cf. [79]). While it represents the maximum willingness to pay, we also examine the impact of lower willingness to pay by applying a cap to the curve. In this approach, values above the cap are reduced to the cap level, while values below remain unchanged.

We assume that hydrogen producers, if necessary, have at most a willingness to pay for excess electricity equal to the current hydrogen price p_{H_2} from the demand curve multiplied by the electrolyzer efficiency η_E:

$$w_{elc}(t) = \eta_E p_{H_2}(t) \quad \text{Eq. 6}$$

Investment in new electrolyzers occurs annually. At the end of each year, hydrogen producers evaluate their profitability and update their outlook of the future by recalculating their investment threshold. For investments in new electrolyzers each hydrogen producer determines their individual willingness to pay for new electrolyzers by solving the NPV analysis for the willingness to pay:

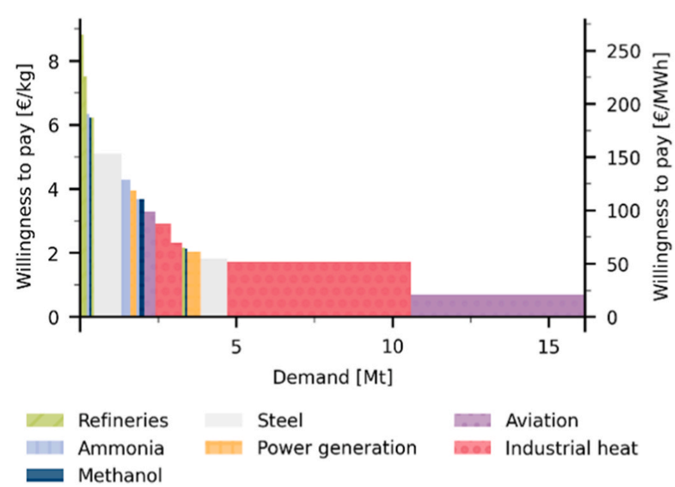

Fig. 3. Willingness to pay for green hydrogen in Germany in 2030 (based on [79]). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

$$\varphi(t) = \frac{\mathrm{NPV}_E}{I_E} \quad \text{Eq. 7}$$

The investment costs I_E are the product of the relative willingness to pay w_E and the planned electrolyzer capacity A_E:

$$I_E = w_E A_E \quad \text{Eq. 8}$$

The NPV is calculated using a constant cash flow Y_E and capital recovery factor CRF_E:

$$\mathrm{NPV}_E = -w_E A_E + \frac{Y_E}{\mathrm{CRF}_E} \quad \text{Eq. 9}$$

Finally, using Eq. (8) and Eq. (9), Eq. (7) can be solved for the relative willingness to pay for electrolyzer capacity:

$$w_E(t) = \frac{Y_E A_E}{(1+\varphi(t))\mathrm{CRF}_E} \quad \text{Eq. 10}$$

Hydrogen producers are ranked in descending order based on their willingness to pay and matched with electrolyzer manufacturers offering the lowest production costs. We assume that electrolyzer manufacturers do not sell at a loss; therefore, the production cost $c_{E,i}$ must be less than or equal to the willingness to pay $w_{E,j}$. The final price for the electrolyzer p_E depends on the market situation and is calculated as:

$$p_E A_E = c_{E,i} A_E + \beta\left(w_{E,j} - c_{E,i}\right) A_E \text{ for } c_{E,i} \le w_{E,j} \quad \text{Eq. 11}$$

Where β is the bargaining factor, that is based on the ratio of maximum demand for electrolyzers $A_{E,D}$ and the maximum supply of electrolyzers $A_{E,S}$:

$$\beta = \frac{1}{2}\frac{A_{E,D}}{A_{E,S}} \text{ for } \frac{A_{E,D}}{A_{E,S}} \le 1 \quad \text{Eq. 12}$$

$$\beta = 1 - \frac{1}{2}\frac{A_{E,S}}{A_{E,D}} \text{ for } \frac{A_{E,D}}{A_{E,S}} > 1$$

The bargaining power is selected in a manner that ensures, in instances where supply and demand are in equilibrium, the price is positioned at the midpoint between the production costs and the willingness to pay for electrolyzers. In scenarios where supply exceeds demand, bargaining power shifts toward the demand side, resulting in a price that approaches production costs, and vice versa.

If no electrolyzer manufacturer can meet the demand – either due to insufficient available production capacity or because the hydrogen producers' willingness to pay is below the production cost – the corresponding hydrogen producer cannot invest in a new electrolyzer. If all existing hydrogen producers successfully invest in new electrolyzers, a new hydrogen producer may enter the market, provided they can buy an electrolyzer. This potential new entrant starts with the lowest investment threshold among all existing hydrogen producers, based on the assumption that a new market participant would adopt the most optimistic outlook upon entry. After entry, the new agent follows the same bidding process as existing producers. The new hydrogen producer is only added to the system if they can purchase an electrolyzer.

3.5. Electrolyzer market

The electrolyzer market operates exclusively on a yearly basis. As outlined in Section 3.4, the production and sale of electrolyzers occur at the end of each year. After that, each electrolyzer manufacturer calculates their profitability and updates their market outlook by adjusting their individual investment threshold. Then electrolyzer manufacturers perform an NPV-analysis for a new factory. The production costs for the new factory are determined based on the cumulative number of electrolyzers produced to date (cf. Eq. (2)). If all existing electrolyzer manufacturers invest in new factories, a new electrolyzer manufacturer is initialized.

3.6. Asset and investor elimination

Finally, at the end of the year, assets that have reached the end of their operational life are eliminated from the system. Investors with no assets by the end of the year are also removed.

4. Experimental setup and results

In this section, we describe the experimental setup and provide an overview of the model's results. The model was executed on a PC equipped with an Intel Xeon E5-2667 processor running at 3.2 GHz and 256 GB of RAM. Leveraging multiprocessing and parallel execution, a scenario comprising 100 runs was completed in under 10 min.

4.1. Experimental setup

We conducted multiple experiments to explore possible pathways toward a profitable green hydrogen industry and to analyze the effects of key exogenous parameters on its dynamics, cf. Table 1.

In the best-case scenario, both the willingness to pay for green hydrogen and the willingness to make strategic investment decisions are at their most favorable levels. This means that the investment threshold for hydrogen producers and electrolyzer manufacturers starts between −0.99 and 0, and the willingness to pay for green hydrogen is as shown in Fig. 3. In the grey hydrogen scenario, the investment threshold also starts between −0.99 and 0; however, the maximum willingness to pay is capped at the marginal costs of grey hydrogen. In the non-strategic case, there is no willingness to make strategic investment decisions, i.e., the investment threshold starts at 0. However, the maximum willingness to pay is again based on Fig. 3. Finally, in the worst-case scenario, there is no willingness to make strategic investment decisions, and at the same time, the maximum willingness to pay for green hydrogen is capped at the marginal costs of grey hydrogen.

In all experiments, the model was initialized to represent the German electricity and green hydrogen industry in 2024. An overview of the most important values at initialization is provided in Table 2. The model starts with 150 GW of installed renewable capacity, 150 MW of installed electrolyzers, and an annual electrolyzer manufacturing capacity of 500 MW. The power sector begins with 27 investors, the hydrogen sector with 6, and the electrolyzer manufacturing sector with 2. Assets are randomly distributed among investors, with at least one asset per investor, and are initialized with a uniform age distribution. The simulation runs for 80 years; however, we focus in our results on the years 2024–2050, which aligns with commonly targeted timelines for decarbonization of Germany.

Carbon prices are kept constant at the same level of €95 per t_{CO2} as used in Ref. [79]. Renewable power generation is modeled to reflect the German energy mix based on installed capacities: 6 % offshore wind, 45 % onshore wind, and 49 % photovoltaics (cf. Ref. [77]). Production costs for electrolyzers start at €2500 per kW [9,11] and the learning rate for electrolyzers is assumed to be 10 % [55].

4.2. Results

The following section presents the results of the experiments

Table 1
Scenario names and characteristics.

		Willingness for strategic investment decision	
		Maximum	None
Maximum willingness to pay for green hydrogen	*Based on* [79]	Best-case	Non-strategic
	Marginal costs of grey hydrogen	Grey hydrogen	Worst-case

Table 2
Parameters at initialization. Lifetime shows the minimal lifetime and in brackets the maximum random additional lifetime an asset can have.

Parameter	Initialization	Source
Power market		
Number of power producers	27	
Non-electrolytic electricity demand	462 TWh/year	[77,78]
Installed capacity renewables	150 GW	[77]
Lifetime renewable asset	20 (+5) years	[80]
Natural gas price	33 €/MWh	[81]
Gas turbine efficiency	40 %	[82]
Investment costs renewable asset	1250 €/kW$_P$	[80]
Capacity factor renewable asset	0.03–0.46	[83,84]
Hydrogen market		
No. of hydrogen producers	6	
Maximum hydrogen demand	543 TWh/year	[79]
Installed capacity electrolyzers	150 MW	[85]
Lifetime electrolyzer asset	15 (+10) years	[86]
Electrolyzer efficiency	70 %	[55]
Steam reforming efficiency	70 %	[87]
Electrolyzer market		
Number of electrolyzer manufacturers	2	
Installed capacity electrolyzer factories	1000 MW/year	[9]
Lifetime electrolyzer factory asset	20 (+5) years	
Investment costs electrolyzer factory	500 €/kW/year	[88–90]
Production costs	2500 €/kW	[9,91]
Learning rate electrolyzers	10 %	[55,67]
Global		
Discount rate	5 %	
CO_2 price	95 €/t$_{CO2}$	[79]

conducted. The graphs shown are based on 100 model runs per scenario. Shaded areas represent the first quartile above and below the median, while thick lines indicate the median – unless stated otherwise.

4.2.1. Best-case scenario

The first scenario explores the best-case for the green hydrogen industry. The willingness to pay for green hydrogen is based on [79] (cf. Fig. 3). In addition, the scenario assumes maximum willingness for strategic investment decisions in the hydrogen and electrolyzer sectors, i.e., the minimal initial value of the investment threshold for both hydrogen and electrolyzer manufacturers is set to $\varphi_{0,max} = -0.99$. This represents the extreme case in our model with the most favorable conditions for the emergence of a green hydrogen industry.

4.2.1.1. A profitable green hydrogen industry. Fig. 4 shows the development of the green hydrogen industry under the best-case scenario. The top graph shows the total installed renewable capacity, the middle graph the total installed electrolyzer capacity, and the bottom graph the total installed electrolyzer manufacturing capacity.

Firstly, the development of the sectors can be categorized into three distinct phases. Phase one (I) exhibits steep linear growth in the power sector until 2028, reaching 277 GW of installed renewables. Phase two (II) is characterized by a growth rate that initially stagnates but then gradually increases, peaking in 2038 at 371 GW installed renewables. The final phase (III) is marked by overall stability.

Secondly, a profitable green hydrogen industry emerges in this scenario, reaching up to 41 GW of installed electrolyzers by 2050. Initially, electrolyzer capacity increases by merely 640 MW until 2029 in phase I. Thereafter, in the 2030s growth accelerates, reaching 34 GW of total installed electrolyzer capacity by 2039 – a 47-fold increase in installed electrolyzers. The expansion of installed electrolyzer capacity follows the typical S-curve observed for the diffusion of new technologies [98].

Finally, the installed manufacturing capacity for electrolyzers begins to grow after a few years and increases steadily between 2025 and 2041. By 2028, manufacturing capacity nearly tripled from 1 to 3 GW/year. After 2029 (phase I), the growth rate of electrolyzer manufacturing capacity stabilizes at approximately 1 GW/year per year until 2041. In 2050 14 GW/year of manufacturing capacity for electrolyzers are

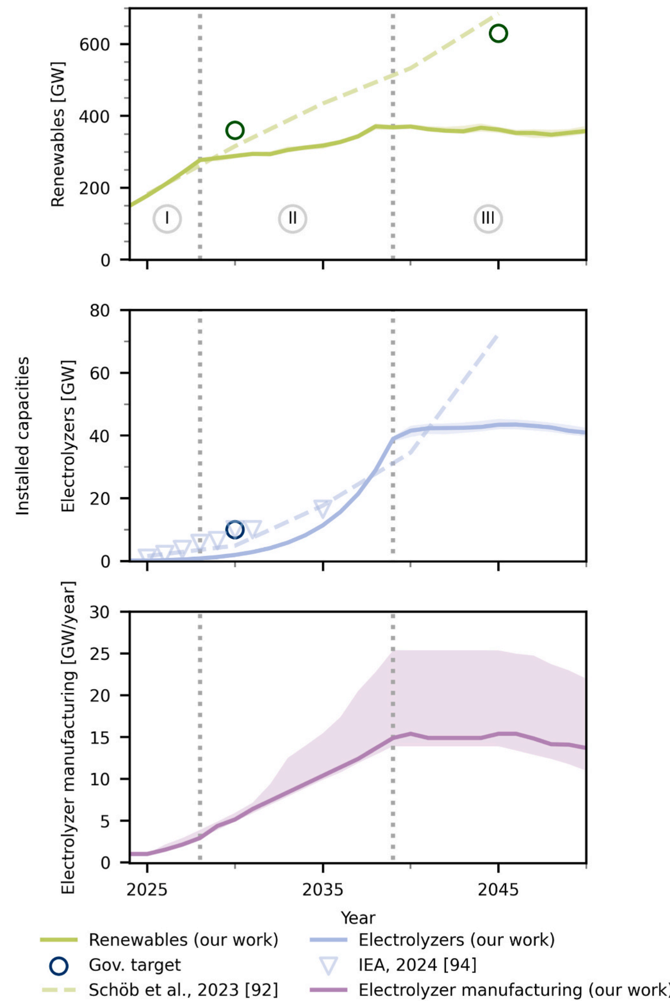

Fig. 4. Installed renewables capacities (top), electrolyzers capacities (middle) and manufacturing capacities for electrolyzers (lower). The solid line and area represents our model results, dashed line model results from Refs. [92,93], triangles the announced electrolyzer projects in Germany from Ref. [94], and circles the German targets for installed renewables and electrolyzers [95–97]. Different phases of the scale-up are indicated by number and their separation by the dashed grey lines in all three sectors. Phase I is the increase in renewables independent of electrolyzers, phase II the scale-up of electrolyzers and phase III the stabilization of all sectors.

installed. Furthermore, a variety of development pathways emerge, with installed manufacturing capacities ranging between 11 and 22 GW/year by 2050. As in the other sectors, the installed manufacturing capacity remains stable in the final years (Phase III).

4.2.1.2. Governmental targets are a pipe dream. Fig. 4 compares our model results with governmental targets for installed renewable and electrolyzer capacities, revealing several key findings. First, none of the targets are met on time. Although renewable capacity grows sufficiently during phase I, the growth rate declines significantly as the primary driver of expansion shifts from market design to electrolyzer deployment. As a result, the targets for installed renewable capacity in 2030 and 2045 are missed, since the number of installed electrolyzers does not generate sufficient electricity demand to support continued expansion.

Moreover, the target of 10 GW of installed electrolyzers by 2030 appears particularly unrealistic, as insufficient excess electricity is available by that time to operate such a capacity profitably.

Note that our results indicate that the governmental targets will not be achieved under the best-case scenario, even though the model allows in principle the required capacities to be attainable.

4.2.1.3. Decarbonization of the power sector. One of the main goals of the transition is the total decarbonization of the electricity sector. Fig. 5 shows the electricity mix normalized by the total electricity demand. The share of renewables increases in two distinct phases: first, a rapid rise until 2028, reaching 79 %, followed by a more gradual increase to 89 % by the late 2030s. In 2050, gas turbines still supply about 50 TWh/year. Although, in our model we have assumed the use of natural gas, other fuels (e.g. hydrogen, biomass) could be used to provide back-up power.

At the same time, while the share of renewables in the electricity mix increases, the share of curtailed electricity by renewables initially rises to over 15 %, however, decreases to about 8 % in 2050 (equivalent to 35 TWh/year) as more electrolyzers are installed, that can use excess electricity.

4.2.1.4. Hydrogen supply for industries. In 2050, a total of 113 TWh of electricity is used for green hydrogen production, meeting a hydrogen demand of 80 TWh or 2.4 Mt of green hydrogen. This results in an average electrolyzer utilization rate of 32 %, consisting of 1345 full-load hours and 3689 partial-load hours. Fig. 6 illustrates the development of green hydrogen production, which ramps up over time and stabilizes around 2039.

Comparison with the demand curve from Fig. 3 reveals that a significant portion of hydrogen demand cannot be met, as the willingness to pay is insufficient for hydrogen producers to operate profitably. This raises the question of whether these customers and their associated industries can remain viable in Germany or need to resort to other technology options in such a future scenario.

4.2.1.5. Reduction potential for electrolyzer production costs. Fig. 7 shows the development of electrolyzer production costs over time. During the initial years, costs remain stable, as installed manufacturing capacities are sufficient to meet demand for new electrolyzers. As electrolyzer manufacturers begin investing in new factories, production costs decrease steadily, reaching approximately €1070 per kW by 2050.

We can see that in the first phase, the relatively small expansion in electrolyzers and their manufacturing capacity already resulted in a significant reduction in production costs by approximately 28 %. During the second phase, minimal production costs declined by an additional 30 % of the original costs, driven by increased electrolyzer deployment and investments in new manufacturing facilities. However, after 2039, a lack of sufficient demand for new electrolyzers removes incentives for factory expansion, resulting in no further reduction in production costs.

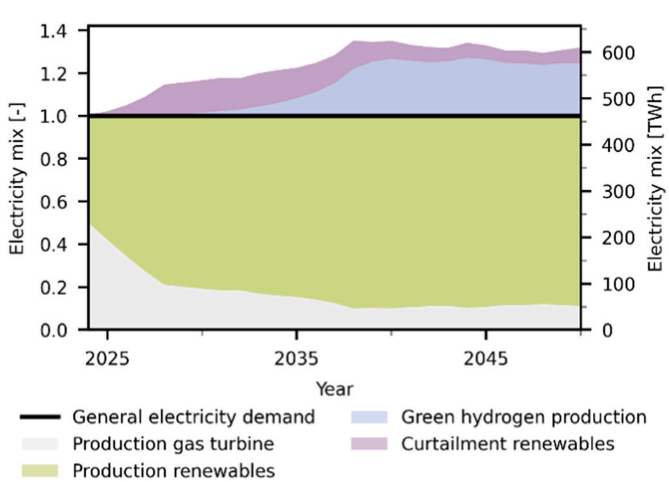

Fig. 5. Electricity mix normalized on the annual non-electrolytic electricity demand and in TWh.

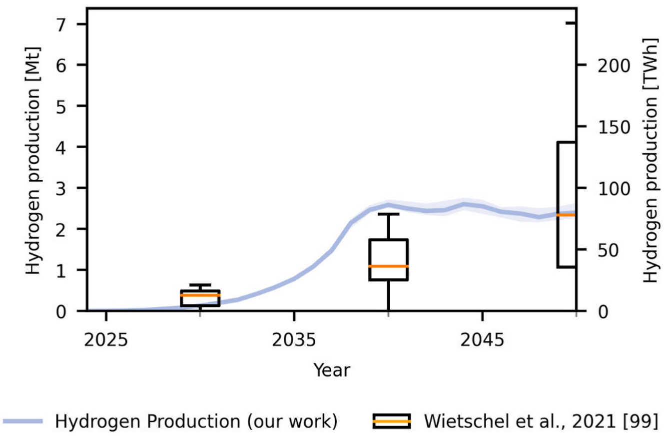

Fig. 6. Hydrogen production for each year. The boxplot represents the range of results for green hydrogen production in Germany from different studies [99]. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

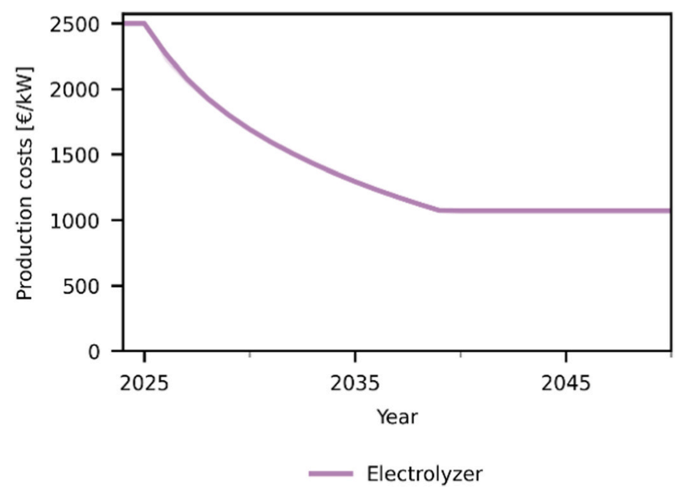

Fig. 7. Minimal electrolyzer production costs at which the cheapest electrolyzer manufacturer can produce each year.

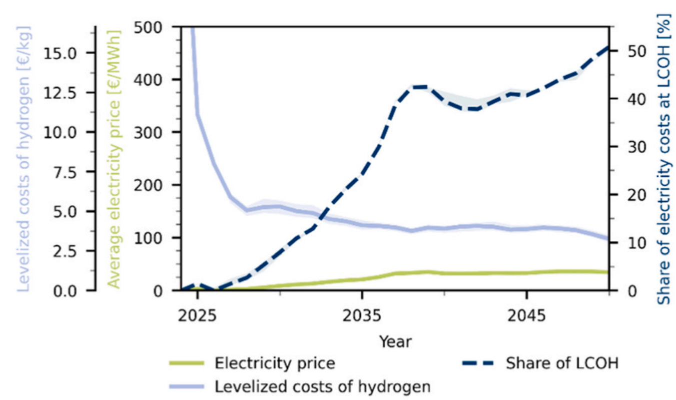

Fig. 8. Comparison of electricity costs for hydrogen producers (green) and the average levelized costs of hydrogen (blue). The share of the electricity costs on the LCOH are shown with a dashed line (dark blue). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

4.2.1.6. The costs of a green hydrogen industry. Finally, we are interested in the costs of a green hydrogen industry and its impact on prices for the non-electrolytic electricity demand and hydrogen. Fig. 8 illustrates the development of the average electricity price paid by hydrogen producers, the levelized cost of green hydrogen (LCOH), and the share of electricity costs within the LCOH over time.

The share of electricity costs within the LCOH increases as the average electricity price paid by hydrogen producers rises to €35 per MWh, driven by growing availability of and demand for excess electricity. While at the same time, investment costs for new electrolyzers decrease due to declining production costs over time (cf. Fig. 7). Although the LCOH stabilizes at the beginning of phase III around €4 per kg or about €120 per MWh and the electricity price around €33 per MWh. In the later years the LCOH decreases to €3.25 per kg or €100 per MWh, however the share of electricity costs only reaches 50 %, indicating that investment costs and the electricity price are both significant parts of the LCOH. This is impacted by the market design chosen for the electricity sector, where electricity costs for hydrogen producers are often zero (cf. Section 3.3).

Fig. 9 illustrates the development of hydrogen prices and the yearly average electricity prices for non-electrolytic electricity demand over time. This allows multiple observations.

Firstly, the price of green hydrogen starts at close to €9 per kg, decreases from around 2031, and stabilizes at approx. €3 per kg. We consider this indicative of a green hydrogen industry nearing stability.

Secondly, the electricity price for non-electrolytic demand decreases in two distinct stages. In the first stage, the price drop – from €119 to 76 per MWh – is driven by the expansion of renewable energy, which is independently of installed electrolyzer capacity. The second stage begins once installed electrolyzer capacity reaches its maximum, with prices declining further to €69 per MWh.

In addition, the levelized cost of electricity (LCOE) for the entire system fluctuates between €53 and 72 per MWh, showing a downward trend over time.

From these observations, we conclude that the existence of a profitable green hydrogen industry reduces the electricity price for non-electrolytic demand. Additionally, the low electricity price required by hydrogen producers for profitability is insufficient by its own for power producers to cover their LCOE. The power producers need to be able to sell to the non-electrolytic electricity demand or at higher prices to hydrogen producers.

Lastly, to address the question of the overall cost of the green hydrogen industry, Table 3 lists investment costs across the three sectors. The largest investment is required in the power sector, amounting to €1234 bn. Hydrogen producers cumulatively invest €82 bn., and

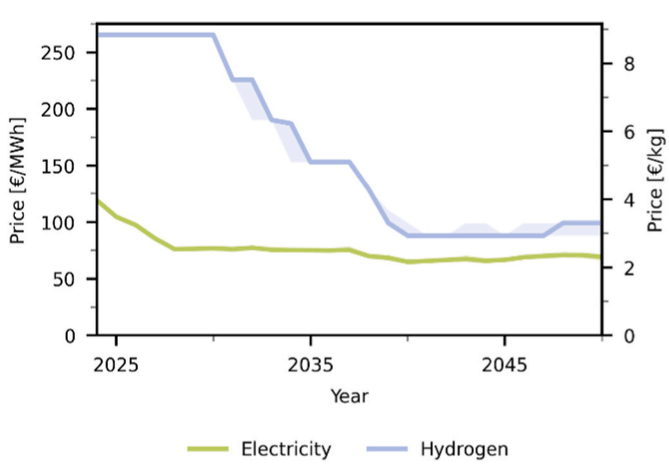

Fig. 9. Comparison of electricity price for the non-electrolytic demand (green) and green hydrogen price (blue). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 3
Comparison of cumulative investment until 2050 in the power, hydrogen and electrolyzer sectors for the best-case, non-strategic, grey hydrogen and worst-case scenario.

Sector	Best-case	Non-strategic	Grey hydrogen	Worst-case
Power	€1234 bn.	€1236 bn.	€1047 bn.	€1025 bn.
Hydrogen	€82 bn.	€75 bn.	€22 bn.	–
Electrolyzer manufacturing	€15 bn.	€13 bn.	€7 bn.	–

electrolyzer manufacturers invest €15 bn. Although there is an order of magnitude difference between the power sectors and the other sectors, it should be noted that power producers supply not only hydrogen producers but also the entire non-electrolytic electricity demand. Moreover, the relatively low investment required by electrolyzer manufacturers results from the fact that the total electrolyzer costs are dominated by OPEX rather than CAPEX (cf. Table 2).

A sensitivity analysis was performed on the electrolyzer learning rate for the best-case scenario. The analysis reveals that higher learning rates lead to increases in installed electrolyzer and manufacturing capacities, accompanied by reductions in electrolyzer costs. However, other key indicators, such as hydrogen production volume, LCOH, hydrogen price, LCOE, and installed renewable capacity remain largely unaffected. Moreover, the overall development dynamics are independent of the assumed learning rate. The detailed results of the sensitivity analysis are presented in Appendix D.

4.2.2. Key parameters for the green hydrogen industry

To understand how our biggest assumption of strategic investment and a premium to pay for green hydrogen will impact the green hydrogen industry, we conducted three additional experiments with more conservative assumptions. In the first scenario, we assume no premium for green hydrogen, instead the maximum willingness to pay is based on the production costs for hydrogen from stream reforming:

$$p_{H_2,max} = \frac{p_{gas}}{\eta_{SR}} \quad \text{Eq. 13}$$

We refer to this scenario as "grey hydrogen". In the second additional scenario, we keep the maximum premium for green hydrogen, however, do not allow for strategic investment, i.e. the minimum starting investment threshold for hydrogen and electrolyzers producers is equal to zero:

$$\varphi_{0,max} = 0 \quad \text{Eq. 14}$$

We refer to this scenario as "non-strategic". In the last, third additional scenario we assume for both, the willingness to pay and the minimum starting investment threshold conservative values, i.e. Eq. (13) and Eq. (14) are true. We call this scenario the "worst-case" for a possible green hydrogen industry.

4.2.2.1. No industry or just slower growth. Fig. 10 shows the development of the installed capacities in the three sectors for the "grey hydrogen", "non-strategic" and the "worst-case" scenario in addition to our best-case scenario.

When comparing the results from the "grey hydrogen" scenario to our best-case scenario, we observe that developments in installed renewables in the power sector are similar during the initial years in phase I. However, after 2028, no significant expansion of renewables occurs in the "grey hydrogen" scenario, stabilizing around 280 GW. The absence of the second increase in renewables, which was observed in the best-case scenario, is due to the significant lower green hydrogen production. In the "grey hydrogen" scenario, the median installed electrolyzer capacity only increases to 12 GW. However, these installed electrolyzers are not replaced after 2050, as these never become profitable. Since this

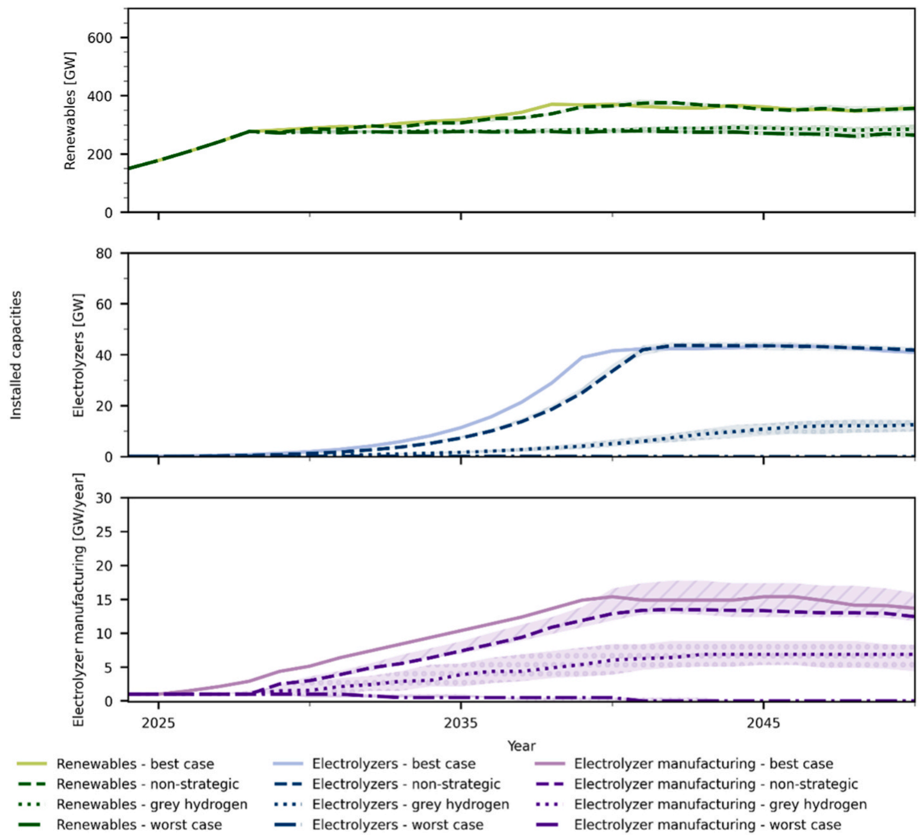

Fig. 10. Comparison of results from best-case (solid), non-strategic (dashed), grey hydrogen (dotted) and worst-case (dashed-dotted) scenario for installed renewables capacities (top), electrolyzers capacities (middle) and production capacities for electrolyzers (lower).

occurs after 2050, it is not observable in Fig. 10. We provide Fig. C 1, showing this investment bubble in Appendix C. A similar pattern – a hype bubble, driven by strategic investment decisions – is observed for electrolyzer production capacities. We conclude that no profitable green hydrogen industry develops in the “grey hydrogen” scenario.

For the “worst-case” scenario, we see that no new electrolyzers are installed and after a while the initial electrolyzers reach the end of their lifetime. The same is true for the manufacturing capacities in this scenario. The installed renewables do increase in the first few years from 150 GW and stabilize around 274 GW. They only sligthly decrease to 265 GW by 2050. With this observation, we can calculate that the ratio of additional installed renewables to installed electrolyzers in a profitable green hydrogen industry in our best-case scenario is around 2.1 GW_R/GW_E.

Comparing the “non-strategic” scenario to the best-case scenario, we observe similar developments in installed renewables as in the other scenarios in phase one. However, after 2029, the installed renewables grow more slowly than in the best-case scenario. This slower growth results from a longer scale-up period of installed electrolyzers in the “non-strategic” scenario compared to the best-case scenario. While the total installed electrolyzer capacity stabilizes around 43 GW in both cases, the time required to reach this level is approximately two years longer in the “non-strategic” scenario. The same delay is observed in the expansion of manufacturing facilities.

4.2.2.2. Costs of being strategic and the costs of a green hydrogen industry. For these four extreme scenarios, we can compare the cumulative investments until 2050 in the three sectors, as shown in Table 3.

Firstly, we observe that the costs for hydrogen producers to act strategically amount to €82 bn. , i.e. 9 % more compared to our “non-strategic” case. At the same time, investment in electrolyzer manufacturing capacities is €2 bn. higher compared to “non-strategic” scenario. The cumulative investments in all three sectors in this scenario are around €6.2 bn, i.e. around 1 %, higher by 2050, as compared to the non-strategic scenario.

Secondly, €1025 bn. are still invested in new renewables in the “worst-case” scenario. This implies that approximately €210 bn. of additional investment in the power sector is required for the green hydrogen industry that develops in both the “non-strategic” and the best-case scenario. Thus, for every €1 invested in electrolyzers, approximately €2.5 must be invested into additional renewables.

4.2.3. Sensitivity to strategic investment decisions and green hydrogen price

To further assess the impact of the level of strategic investment and the premium paid for green hydrogen, we explored the industry’s development under different combinations of these two parameters with a sensitivity analysis. We vary the willingness to pay between €3 and 8 per kg in €1 per kg increments, and the investment threshold between −1 and 0 in 0.1 increments.

4.2.3.1. What is needed for a profitable green hydrogen industry?. Fig. 11 shows the installed electrolyzer capacity in different scenarios in the year 2050. A clear distinction can be observed between parameter combinations that result in a profitable green hydrogen industry and those in which no industry develops. At a minimum, a willingness to pay €4 per kg for green hydrogen is required for an industry to develop in the model. This indicates that with a lower appetite for risk among hydrogen and electrolyzer manufacturers, a higher maximum willingness to pay for green hydrogen is necessary and vice versa. However, with a maximum willingness to pay of €5 per kg strategic investment decisions are not necessary anymore.

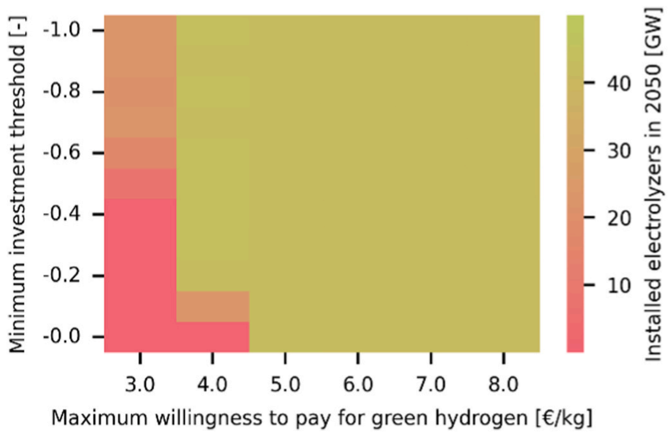

Fig. 11. Sensitivity of installed electrolyzers in 2050 to maximum willingness to pay for green hydrogen and minimum starting investment threshold. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

5. Discussion

Using our simplified conceptual and model, we have simulated the co-development of the power, hydrogen, and electrolyzer sectors from 2024 to 2050. We validated the power sector component of our model against historical data, with the corresponding results provided in Appendix E. For the period from 2000 to 2024, our results show a mean absolute percentage error of 16.2 % for installed renewable capacity, 15.7 % for the share of renewables in total electricity production, and 10.6 % for renewable electricity production. Due to the high-level, abstract nature of our model and the current non-existence of the green hydrogen industry, we validate our results by comparison to literature.

5.1. Comparison to literature

The development of the green hydrogen industry is an active field of research. Many studies have been conducted on green hydrogen industry in Germany. Table 4 shows how our key results compare to values reported in literature. For comparison, we consider meta-studies that aggregate results from multiple individual studies.

Table 4
Comparison of key results of literature and current model (best-case scenario). Values for literature show range from minimum to maximum and if available the median in brackets. Values for current model show 25- and 75-percentile and median in brackets.

Result	Current model (best-case)	Literature	Source
Installed electrolyzers 2030	1.9–2.1 (2.0) GW	5-21 (5) GW	[100]
Installed electrolyzers 2045/50	39.7–42.5 (41.0) GW	11-147 (36) GW	[100]
Installed renewables 2030	282-293 (289) GW	195-390 (256) GW	[100]
Installed renewables 2045/50	351-372 (358) GW	270-856 (490) GW	[100]
Hydrogen production 2030	4.0–4.6 (4.4) TWh	0-335 (11) TWh	[99]
Hydrogen production 2050	75.4–87.8 (80.0) TWh	0-644 (78) TWh	[99]
Electrolyzer price 2030	1674-1700 (1692) €/kW	400-1850 €/kW	[101, 102]
Electrolyzer price 2050	1065-1073 (1072) €/kW	220-650 €/kW	[103]
LCOH 2030	4.83–5.67 (5.29) €/kg	3.06–3.69 €/kg	[104]
LCOH 2050	3.03–3.49 (3.25) €/kg	1.40–4.38 €/kg	[105, 106]

Comparing our results shows that our model simulates a green hydrogen industry in 2050 similar to literature in the best-case scenario. However, our model appears to differ in the pathway it takes to reach a profitable green hydrogen industry. Our results for 2030 are consistently less favorable for a green hydrogen industry than those reported in the literature, while for 2050, our results align closer with literature values, close to the mean or median.

For the power sector, our 2030 results align with the literature, as the main driver for expansion is not green hydrogen production but financial incentives from fossil fuel power plants in the merit order. However, like all but one study in the meta-analysis, the 2030 policy goal is not met, despite a high expansion rate of renewables already achieved, highlighting the ambitious nature of this target. Differences in installed renewables for 2050 between our model and other studies may be due to various factors such as different methods, policy or electricity demand assumptions, and available technology options. Our model indicates that without increased electricity demand, green hydrogen alone does not provide sufficient incentives to install the renewables necessary to meet the policy target. Only about 30 % of studies analyzed in the meta-study achieve the target for installed renewables by 2050.

Regarding the hydrogen sector, two differences stand out. First, our model shows that the rollout of electrolyzers occurs later than in other models. Nevertheless, the final state of the industry is comparable with literature results, with key indicators such as installed electrolyzers, and hydrogen production showing reasonable consistency. Differences between our results and other studies may be attributed to factors such as green hydrogen imports, modeling methods, or hydrogen demand. Variations in import quotas and hydrogen demand explain the wide range of reported hydrogen production levels. Both the meta-analysis studies and our results suggest that the policy target of 10 GW installed electrolyzers by 2030 is overly ambitious.

Second, both the starting point at which significant investment in electrolyzers begins around 80 % renewable electricity – and the ratio of additional renewable capacity to electrolyzer capacity – approximately 2 GW_R/GW_E – are comparable to values reported in the literature (cf. Ref [107]).

In addition, the relative reduction potential of electrolyzer production costs is similar. As mentioned earlier, we assumed very high initial production costs and a low learning rate for turnkey electrolyzers, leading to a lower total reduction potential for electrolyzers. However, the production costs for 2050 are in line with what is mentioned in Ref. [11].

5.2. Discussion of the industry scale-up

The developments observed in our model lead to the following key insights:

A profitable green hydrogen industry in Germany is feasible. Given the right combination of willingness to pay a premium for green hydrogen and a high level of strategic investment decisions by hydrogen and electrolyzer manufacturers, an industry with approximately 40 GW of installed electrolyzer capacity and the necessary production infrastructure can emerge. This industry could produce hydrogen at levelized costs (LCOH) around €3 per kg by 2050 using exclusively excess electricity. While other studies have already suggested that a domestic green hydrogen industry may be the cost-optimal solution (cf. Section 5.1), we have demonstrated that such an industry can also be profitable under the right conditions. However, the industry relies on both investors being willing to make strategic investment decisions and hydrogen consumers being willing to pay a premium for green hydrogen.

The green hydrogen industry benefits non-electrolytic electricity consumers. This is a novel and potentially counterintuitive result. We attribute this to the fact that electrolyzer deployment incentivizes the installation of additional renewable capacity. As a result, the volume of excess electricity increases, which leads to more hours with lower electricity prices compared to situations when gas turbines must supply part of the non-electrolytic electricity demand. While the use of electrolyzers raises electricity prices during some excess electricity periods (since prices are no longer zero), the overall cost-lowering effect of having more hours with excess supply outweighs this increase.

Strategic investment is costly. Strategic investment decisions increase the likelihood of a profitable green hydrogen industry emerging. This is consistent with real-world behavior, where hydrogen and electrolyzer manufacturers invest in or announce new projects despite the associated risks. However, our model does not account for insolvency, which may result in underestimating the risks of strategic investment decisions. In addition, strategic investment decisions by hydrogen producers and electrolyzer manufacturers also increase the overall amount invested.

Policy makers are needed. Our results show that a profitable green hydrogen industry requires a combination of strategic investment and a willingness to pay for green hydrogen. This is where policymakers play a crucial role. They can facilitate strategic investments by setting clear industry targets, as done by the EU [5] and Germany [95]. Appropriate policy instruments such as Hy2Tech under the Important Projects of Common European Interest [108] can support these goals by reducing investment risks and thereby making strategic commitments more attractive. Moreover, policies such as Hy2Use [109] or the auctions by the European Hydrogen Bank [110] can increase the willingness to pay for green hydrogen, or reduce the price of green hydrogen. Policymakers thus have several levers at their disposal to influence the development of the sector.

5.3. Discussion on conceptualization and parameterization

The conceptualization of the decision-making process within an agent-based model is a critical element. In our study, we deliberately adopt a keep-it-simple approach by basing investment decisions on a net present value analysis. We acknowledge that real-world investor behavior is more complex and influenced by a range of factors – including preferences for certain asset types, prior experience, and broader macroeconomic trends. However, we argue that our simplified approach is justified, as many of these factors are difficult or impossible to quantify.

In our model, we have simplified the electricity sector as an energy-only market. Additionally, we have assumed that the non-electrolytic electricity demand remains constant until 2050. While many studies predict an increase in non-electrolytic electricity demand due to rising electrification, we believe that accounting for this would introduce unnecessary complexity and uncertainty regarding how much the demand would increase, into our results.

While the CO_2 price influences both the electricity market and the demand for green hydrogen, its future trajectory is highly uncertain. Moreover, it is affected – though not solely determined – by developments within the sectors represented in our model. For simplicity, we have therefore assumed a constant CO_2 price throughout the simulation period. A higher CO_2 price would likely stimulate additional deployment of renewable energy sources and electrolyzers. However, the impact on other results is difficult to predict.

On the technical side, we decided to exclude other technologies than renewables in the electricity sector to keep the model as simple as possible. The inclusion of technologies such as different renewables technologies, steam or gas turbines would add complexity without altering our fundamental findings. An interesting addition could be the use of green hydrogen in the power sector, as it presents another potential demand for green hydrogen. However, this is outside the scope of our research. Likewise, the modeling of electricity storage technologies, while an intriguing addition, was not part of the model but could be valuable, as these technologies also use excess electricity. Their inclusion could, on the one hand, provide an additional revenue stream for power producers and thereby encourage further investment, potentially leading to greater installed renewable capacity. On the other hand, it could also result in an overestimation of the profitability of hydrogen producers and the installed capacity of electrolyzers.

Although our source for green hydrogen demand accounts for different sectors and industries, the model does not capture feedback effects on this demand and does not include all sectors (e.g., the transport sector). While demand assumptions are an essential aspect of the model and affect the results, a full modeling of all these interdependencies would exceed the scope of this study.

We acknowledge that the market for electrolyzers could be expanded internationally. However, the literature suggests that this will not happen in the near future, and that electrolyzer manufacturers in China, Europe, and the USA will focus primarily on their home regions [10].

We decided not to account for the import of green hydrogen due to the many uncertainties surrounding price and availability, particularly as potential exporting countries may prioritize decarbonizing their own energy systems. That said, if low-cost hydrogen becomes available, it could affect our results. Therefore, the prices and LCOH from our model should be interpreted as valid only if inexpensive imports are not available in sufficient quantities.

Furthermore, we acknowledge that the values we assumed for the parameterization (cf. Table 2) carry uncertainties and ranges. For installed electrolyzer manufacturing capacities, we were only able to find a number for Europe but have made an educated guess for the German part.

However, to the best of our knowledge and based on a comprehensive review of existing studies, no previous modeling effort has integrated all three key sectors required for a green hydrogen industry into a unified agent-based model while also incorporating a framework for strategic investment behavior. Existing agent-based models have only explored the interaction between renewable energy deployment and electrolyzer investment, cf. Ref. [44].

6. Conclusion

In this study, we developed an agent-based model that simulates investor behavior across the electricity, hydrogen, and electrolyzer markets. We modeled the future growth and coupled development of each of these. The results highlight the dynamics of the green hydrogen industry's development. Through scenario analysis, we linked these dynamics to fundamental drivers such as the strategic risk appetite of investors and willingness of the market to pay a premium for green hydrogen.

Agent-based models are particularly well suited to exploring the role of individual actors in complex systems. We followed a 'keep-it-simple' principle, acknowledging that modeling three interacting sectors already introduces considerable complexity. Nevertheless, we argue that this study offers new insights through a simple and transparent approach. In addition, we were able to incorporate strategic investment behavior in the model: hydrogen producers and electrolyzer manufacturers may decide to invest in assets without expecting direct profitability in order to gain a first-mover advantage.

Our results underscore that the availability of excess electricity and domestic electrolyzer manufacturing capacity are essential prerequisites for scaling up a green hydrogen industry. However, successful industry development is not guaranteed. The willingness to pay is a decisive factor in determining whether a profitable green hydrogen industry can emerge. Even under maximum strategic investment, a willingness to pay €4 per kg for green hydrogen is required during the initial phase of the scale-up. If investors behave less strategically in their investment, this threshold increases to €5 per kg. Nonetheless, once the industry scales up, the levelized cost of hydrogen can fall to around €3 per kg in Germany as the cost of electrolyzers falls to circa €1000 per kW due to technological learning.

If a scale-up occurs, it can be divided into three phases. First, in the 2020s only the power sector decarbonizes through deployment of additional renewables. There is no significant electrolyzer capacity addition as there is insufficient excess electricity available to utilize electrolyzers effectively. Second, from the early 2030s onward there is continued power sector decarbonization as well as expansion of electrolyzer capacity and electrolyzer manufacturing capacity. Third, the system transitions into a stabilization phase around 2040, during which only end-of-life assets are replaced. Reaching this profitable green hydrogen industry with 40 GW of electrolyzer capacity and halving the ca. 20 % remaining non-electrolytic power demand not met directly with renewables in 2030, require investments in electrolyzer capacity of around €80 bn. and additional investments in renewables of around €200 bn. up to 2050.

Different investment strategies influence the timing of the scale-up if an industry develops. With the most strategic investment decisions, the scale-up occurs approximately two years earlier than without any strategic investment decisions. However, this comes at a cost of about €6 bn. Nevertheless, the final outcome – around 40 GW of installed electrolyzers by 2050 – is largely independent of the degree of strategic behavior, as long as the willingness to pay for green hydrogen is high enough.

We show that, while policy targets can drive strategic investments, they are unlikely to be met on time. Before 2030, electrolysis deployment remains limited until the point where there is sufficient excess electricity to warrant electrolyzer deployment. Afterward its expansion is limited by slow growth of excess renewable electricity and time required to scale up electrolyzer manufacturing capacities.

Our findings suggest that, to promote a domestic green hydrogen industry, policy makers need to guarantee not only sufficient excess electricity but also a willingness among consumers to pay a premium for green hydrogen. Additionally, we demonstrate that investors in electrolyzers face a limited temporal window for the perfect market entry, shaped by the availability of excess electricity and the potential for cost reductions in electrolyzer technology.

Future research could extend the model to include electricity storage technologies such as batteries as investment opportunities, to assess their effect on the availability of excess electricity. Moreover, the explicit use of green hydrogen in the power sector could be examined as a means to further decarbonize electricity generation.

Incorporating and coupling additional sectors, such as the transport sector, into the demand modeling could provide a more comprehensive view and reveal interesting dynamics, which should be explored in future research. Moreover, the model could be extended to account for international trade, enabling an assessment of the impact of international imports on the German hydrogen industry and electrolyzer manufacturing, as well as their export capabilities.

Lastly, the model could be extended to incorporate different policy instruments, to analyze their impact on industry scale-up. This method could support evidence-based policy design, by allowing policymakers to assess the effectiveness of proposed measures.

CRediT authorship contribution statement

Bernhard-Johannes Jesse: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Gert Jan Kramer:** Writing – review & editing, Validation, Supervision, Methodology, Formal analysis, Conceptualization. **Imke Rhoden:** Writing – review & editing, Supervision, Funding acquisition. **Vinzenz Koning:** Writing – review & editing, Validation, Supervision, Methodology, Formal analysis, Conceptualization.

Availability of data and materials

Data will be made available on request.

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Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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During the preparation of this work the authors used DeepL in order to improve readability and the language. After using this tool, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2025.152695.

A. Appendix A.

Model narrative

Our model simulates the development of the green hydrogen industry and the power system over several years. The smallest time step within each year is one day. Each day, renewable electricity production, electricity prices, and electrolyzer activity are modeled. At the end of each year, the following steps occur:

Power producers calculate their profitability. Power producers calculate their income from each asset in their portfolio based on daily electricity production and prices. They then determine the profitability of each asset. Based on the profitability of their assets, power producers adjust their investment threshold.

Power producers evaluate new investment opportunities. Power producers assess new investments by performing an NPV calculation based on expected profits and capacity. Expected profits are estimated from the past year’s renewable utilization and electricity prices. If the ratio of NPV to investment costs exceeds the investor’s individual investment threshold, a new asset is added to the system and begins generating electricity the following year.

New power producer entry if possible. If all power producers have decided to invest in new assets, a new investor may enter the electricity sector. This new investor is initialized with a random investment threshold and one renewable asset. Since capital is limited, only one new investor may enter the market per year.

Hydrogen producers calculate their profitability. Hydrogen producers calculate their asset profitability similarly to power producers and adjust their investment thresholds based on asset performance.

Hydrogen producers evaluate new investment opportunities. There is no guarantee that electrolyzers will be available. Hydrogen producers calculate their willingness to pay for electrolyzers using their investment thresholds and an NPV analysis. They submit bids to electrolyzer manufacturers. Electrolyzer manufacturers sell their electrolyzers to the highest bidders, starting with the electrolyzer manufacturer with the lowest production costs, until no more production capacities for electrolyzers are available or no more bids are placed. New electrolyzers begin producing green hydrogen the following year.

New hydrogen producer entry if possible. After all hydrogen producers acquire electrolyzers, a new hydrogen producer may enter the sector if they can purchase an electrolyzer. The new producer's willingness to pay is based on a random investment threshold, and they bid accordingly. If the bid is accepted, the new hydrogen producer enters the market. As with power producers, only one new investor may enter per year.

Electrolyzer manufacturers calculate their profitability. Electrolyzer manufacturers calculate their profitability after selling electrolyzers, considering profits, production costs, and equivalent annual costs. They adjust their investment threshold accordingly.

Electrolyzer manufacturers evaluate new investment opportunities. Electrolyzer manufacturers evaluate investments similarly to power producers. Upon a positive decision, production costs are calculated, a new factory is initialized, and the factory becomes operational the following year.

New electrolyzer manufacturer entry if possible. If all electrolyzer manufacturers invest in new factories, a new investor may enter the electrolyzer market. The new producer starts with a random investment threshold and one electrolyzer factory. Only one new investor may enter per year.

Asset and investor elimination. Assets reaching the end of their operational life are removed from the system. Investors with no remaining assets at the end of the year are also eliminated.

List of symbols

Tab. A 1
List of symbols.

Symbol	Meaning	Symbol	Meaning
α_j	Risk tolerance factor of hydrogen producer *j*	CRF_R	Capital recovery factor for renewable
α_k	Risk tolerance factor of electrolyzer manufacturer *k*	D_{elc}	Non-electrolytic electricity demand
β	Bargaining power factor	I	Investment costs
η_E	Efficiency electrolyzers	I_E	Investment costs of electrolyzer
η_{GT}	Efficiency gas turbine	$I_{E,j}$	Investment costs for electrolyzer for hydrogen producer *j*
λ	Learning rate for electrolyzers	$I_{E,n}$	Investment costs of electrolyzer *n*
$\omega_{A,j}$	Weight for capacity for hydrogen producer *j*	I_F	Investment costs for electrolyzer manufacturing factory
$\omega_{c,j}$	Weight for costs for hydrogen producer *j*	i_F	Specific investment costs electrolyzer manufacturing factory
φ	Investment threshold	$I_{F,p}$	Investment costs for factory for electrolyzer manufacturer *k*
φ_i	Investment threshold of power producer *i*	I_R	Investment costs of renewable
$\Delta\varphi_i$	Change in investment threshold for power producer *i*	i_R	Specific investment cost renewable
φ_j	Investment threshold of hydrogen producer *j*	N_E	Number of electrolyzers
$\varphi_{j,0}$	Investment threshold of hydrogen producer *j* at initialization	N_{EP}	Number of electrolyzer manufacturers
$\Delta\varphi_j$	Change in investment threshold for hydrogen producer *j*	N_F	Number of factories for electrolyzer manufacturing
φ_k	Investment threshold of electrolyzer manufacturer *k*	N_{HP}	Number of hydrogen producers
$\varphi_{k,0}$	Investment threshold of electrolyzer manufacturer *k* at initalization	N_R	Number of renewables
$\Delta\varphi_j$	Change in investment threshold for electrolyzer manufacturer *k*	$N_{S,k}$	Number of sales of electrolyzers of electrolyzer manufacturer *k*
$\Delta\varphi_{max,i}$	Maximum change in investment threshold for power producer *i*	NPV	Net present value
$\Delta\varphi_{max,j}$	Maximum change in investment threshold for hydrogen producer *j*	NPV_E	Net present value of electrolyzer
$\Delta\varphi_{max,k}$	Maximum change in investment threshold for electrolyzer manufacturer *k*	$\mathrm{NPV}_{E,j}$	Net present value of electrolyzer of hydrogen producer *j*
		$\mathrm{NPV}_{F,k}$	Net present value of electrolyzer manufacturer *k*
A_E	Capacity of electrolyzer	$\mathrm{NPV}_{R,i}$	Net present value of renewable of power producer *i*
$A_{E,0}$	Capacity of electrolyzers in year zero	p_E	Price electrolyzers
$A_{E,cum}$	Cumulative electrolyzers capacity produced	P_E	Total production electrolyzers
$A_{E,D}$	Maximum demand for electrolyzers	$p_{E,jk}$	Price for electrolyzer for sale between hydrogen producer *j* and electrolyzer manufacturer *k*
$\Delta A_{E,k}$	Difference in capacity for electrolyzer manufacturer *k*	$p_{E,s}$	Price of electrolyzer in sale *s*
$A_{E,max}$	Maximum capacity for electrolyzer	p_{elc}	Electricity price
$\Delta A_{E,max}$	Maximum difference in capacity	p_{gas}	Natural gas price
$A_{E,n}$	Capacity of electrolyzer *n*	p_{H_2}	Hydrogen price
$A_{E,S}$	Maximum supply of electrolyzers	$P_{R,all}$	Current maximum output of renewables
$A_{E,s}$	Capacity of electrolyzer in sale *s*	$P_{R,all,max}$	Current maximum output of renewables
$A_{E,target}$	Political target for cumulative electrolyzer capacity	r	Discount rate
A_F	Capacity of electrolyzer manufacturing factory	ROI_i	Return of investment of power producer *i*
$A_{F,max}$	Maximum capacity for electrolyzer manufacturing factory	ROI_j	Return of investment of hydrogen producer *j*
$A_{F,p}$	Capacity of factory for electrolyzer manufacturing *p*	ROI_k	Return of investment for electrolyzer manufacturer *k*
A_R	Capacity of renewable	$\mathrm{ROI}_{target,i}$	Target return of investment of power producer *i*
$A_{R,m}$	Capacity of renewable *m*	$\mathrm{ROI}_{target,j}$	Target return of investment of hydrogen producer *j*
$A_{R,max}$	Maximum capacity for renewable	$\mathrm{ROI}_{target,k}$	Target return of investment of electrolyzer manufacturer *k*
$B_{E,n}$	Benefits of electrolyzer *n*	T_E	Minimal lifetime electrolyzer
B_i	Benefits of power producer *i*	T_F	Minimal lifetime of electrolyzer manufacturing factory
$B_{R,m}$	Benefits of renewable *m*	T_R	Minimal lifetime renewable
c_{CO_2}	CO_2 price	u_E	Utilization of electrolyzers

(*continued on next page*)

Tab. A 1 (*continued*)

Symbol	Meaning	Symbol	Meaning
c_E	Production costs of electrolyzer	u_R	Utilization of renewables
$c_{E,0}$	Production costs of electrolyzer in year zero	w_E	Willingness to pay for electrolyzers
$c_{E,i}$	Production costs for electrolyzer i	$w_{E,j}$	Willingness to pay for electrolyzer by hydrogen producer j
$c_{E,k}$	Production costs for electrolyzer manufacturer k	w_{elc}	Willingness to pay for electricity
$c_{E,max}$	Maximum production costs for electrolyzer	Y_E	Cashflow for electrolyzer
$C_{E,n}$	Expenditure of electrolyzer n	$Y_{E,n}$	Cashflow or electrolyzer n
$c_{E,s}$	Production costs of electrolyzer in sale s	Y_i	Cashflow of renewable of power producer i
c_{gas}	Costs natural gas	y_i	Specific cashflow of renewable
cf_R	Capacity factor renewables	Y_j	Cashflow of hydrogen producer j
ci_{gas}	Carbon intensity natural gas	Y_k	Cashflow of electrolyzer manufacturer k
CRF_E	Capital recovery factor for electrolyzer	y_k	Specific cashflow of electrolyzer manufacturing factory
CRF_F	Capital recovery factor for electrolyzer manufacturing factory	$Y_{R,m}$	Cashflow of renewable m

Model logic

The model works on two timescales: daily and yearly. We first describe all actions done on a daily scale.

Daily actions

First, we determine the maximum possible production by all renewables $P_{R,all,max}$:

$$P_{R,all,max} = cf_R \sum_{m=0}^{N_R} A_{R,m} \qquad \text{Eq. 15}$$

Where cf_R is the weather dependent capacity factors for renewables, $A_{R,m}$ the capacity of Renewable m, and N_R is the number of installed renewables. Next, we calculate the actual production by renewables $P_{R,all}$:

$$P_{R,all} = u_R \sum_{m=0}^{N_R} A_{R,m} \qquad \text{Eq. 16}$$

Where u_R is the utilization of renewables:

$$\begin{aligned} u_R &= cf_R && \text{for } P_{R,all,max} \le D_G + \sum_{n=0}^{N_E} A_{E,n} \\ u_R &= \frac{D_G + \sum_{n=0}^{N_E} A_{E,n}}{P_{R,all,max}} && \text{for } P_{R,all,max} > D_G + \sum_{n=0}^{N_E} A_{E,n} \end{aligned} \qquad \text{Eq. 17}$$

Where D_G is the non-electrolytic electricity demand, $A_{E,n}$ is the capacity of electrolyzer n, and N_E is the number of installed electrolyzers. Similarly, we can also determine the utilization of the electrolyzers:

$$\begin{aligned} u_E &= 0 && \text{for } P_{R,all,max} \le D_G \\ u_E &= \frac{P_{R,all} - D_G}{\sum_{n=0}^{N_E} A_{E,n}} && \text{for } D_G < P_{R,all,max} < D_G + \sum_{n=0}^{N_E} A_{E,n} \\ u_E &= 1 && \text{for } P_{R,all,max} \ge D_G + \sum_{n=0}^{N_E} A_{E,n} \end{aligned} \qquad \text{Eq. 18}$$

In addition, we can determine the price of electricity p_{elc}, which is also dependent on the production by renewables $P_{R,all,max}$.

$$\begin{aligned} p_{elc} &= \frac{p_{gas}}{\eta_{GT}} && \text{for } P_{R,all,max} < D_G \\ p_{elc} &= w_{elc} && \text{for } D_G < P_{R,all,max} < D_G + \sum_{n=0}^{N_E} A_{E,n} \\ p_{elc} &= 0 && \text{for } P_{R,all,max} \ge D_G + \sum_{n=0}^{N_E} A_{E,n} \end{aligned} \qquad \text{Eq. 19}$$

Where η_{GT} is the efficiency of gas turbines and p_{gas} is the price for gas, which depends on the CO_2-price c_{CO_2}, the carbon intensity of natural gas ci_{gas}, and the costs for natural gas c_{gas}:

$$p_{gas} = c_{gas} + ci_{gas} c_{CO_2} \qquad \text{Eq. 20}$$

Furthermore, w_{elc} is the willingness to pay for electricity by hydrogen producers, which is based on the efficiency of the electrolyzers η_E and the price for green hydrogen p_{H_2}.

$$w_{elc} = p_{H_2}\eta_E \quad \text{Eq. 21}$$

The price for green hydrogen is determined with the help of Fig. 3 and the total green hydrogen production P_E from the previous year $t-1$:

$$P_E(t-1) = \sum_{d=0}^{365} u_E(d) \sum_{n=0}^{N_E} A_{E,n} \quad \text{Eq. 22}$$

Where $u_E(d)$ is the electrolyzer utilization on day d, N_E is the number of electrolyzers and $A_{E,n}$ is the capacity of electrolyzer n.

Yearly actions - Power producer

We start describing the yearly actions for the power producers. We calculate the return on investment ROI_i for power producer i:

$$\mathrm{ROI}_i = \frac{\sum_{m=0}^{N_{R,i}} B_{R,m}}{\sum_{m=0}^{N_{R,i}} I_R} \quad \text{Eq. 23}$$

Where $B_{R,n}$ is the benefits earned by renewable m of power producers i, $I_{R,n}$ are the investment costs of renewable, and $N_{R,i}$ is the number of renewables of power producer i.

With the return of investment ROI_i we can calculate the change in the investment threshold $\Delta\varphi_i$ for the power producer i:

$$\Delta\varphi_i = -\Delta\varphi_{max,i} {}^* \tanh\left(ln\left(\frac{\mathrm{ROI}_i}{\mathrm{ROI}_{target,i}}\right)\right) \quad \text{Eq. 24}$$

Where $\Delta\varphi_{max,i}$ is the maximum change possible for power producer i, and $\mathrm{ROI}_{target,i}$ is the target return of investment for power producer i at which the power producer achieves profitability. We can calculate this by setting the net present value $\mathrm{NPV}_{R,i}$ of a renewable asset of power producer i equal zero and then solving for the necessary return on investment:

$$\mathrm{NPV}_{R,i} \overset{!}{=} 0 \quad \text{Eq. 25}$$

The net present value $\mathrm{NPV}_{R,i}$ can be calculated as follows for a constant cashflow Y_i of power producer i:

$$\mathrm{NPV}_{R,i} = -I_R + \frac{Y_i}{\mathrm{CRF}_R} \quad \text{Eq. 26}$$

Where I_R is the investment costs for a renewable and the capital recovery factor CRF_R for a renewable asset. The cashflow Y_i is equal to the benefits B_i for renewables since they have no fuel costs:

$$Y_i = B_i \quad \text{Eq. 27}$$

We can calculate the capital recover factor CRF_R for a renewable asset with the internal discount rate r, and T_R the lifetime of a renewable asset.

$$\mathrm{CRF}_R = \frac{r}{1-(1+r)^{-T_R}} \quad \text{Eq. 28}$$

With Eq. (26) and Eq. (28) we can solve Eq. (25) to solve for the target return on investment $\mathrm{ROI}_{target,i}$:

$$-I_R + \frac{Y_i}{\mathrm{CRF}_R} \overset{!}{=} 0 \quad \text{Eq. 29}$$

$$I_R = \frac{Y_i}{\mathrm{CRF}_R} \quad \text{Eq. 30}$$

$$\frac{Y_i}{I_R} = \mathrm{CRF}_R \quad \text{Eq. 31}$$

$$\mathrm{ROI}_{target,i} = \mathrm{CRF}_R \quad \text{Eq. 32}$$

Finally, we can update the investment threshold $\varphi_i(t)$ of power producer i for year t:

$$\varphi_i(t) = \varphi_i(\mathrm{t}-1) + \Delta\varphi_i \quad \text{Eq. 33}$$

Where the power producer's individual investment threshold can never fall below zero:

$$\varphi_i \geq 0 \quad \text{Eq. 34}$$

The power producer then makes an investment decision based on the expected net present value $NPV_{R,i}$ of a new renewable, investment costs I_R and the updated investment threshold $\varphi_i(t)$:

$$\varphi_i(t) \leq \frac{\mathrm{NPV}_{R,i}}{I_R} \quad \text{Eq. 35}$$

The net present value $NPV_{R,i}$ of the new renewable is based on the specific investment costs for renewables i_R, the capital recovery factor for renewables CRF_R, the capacity of the new renewable asset A_R and the specific cashflow y_i, which is assumed to be constant:

$$\mathrm{NPV}_{R,i} = -i_R A_R + \frac{y_i A_R}{\mathrm{CRF}_R} \quad \text{Eq. 36}$$

The assumed specific cashflow y_i is equal to the specific average cashflow of the existing assets of power producer i:

$$y_i = \frac{\sum_{m=0}^{N_{R,i}} Y_{R,m}(t)}{\sum_{m=0}^{N_{R,i}} A_{R,m}} \quad \text{Eq. 37}$$

Where $N_{R,i}$ is the number of renewable assets of power producer i, $Y_{R,m}(t)$ is the cashflow of renewable asset m earned in the current year t, and $A_{R,m}$ is the capacity of renewable asset m.

If a positive investment decision was made in one year, the capacity for the next renewable asset A_R is increased as follows:

$$A_R(t+1) = A_R(t) + \Delta A_R \text{ for } A_R(t) < A_{R,max} \quad \text{Eq. 38}$$

Where $A_{R,max}$ is the maximum capacity of renewable assets and is the ΔA_R increase in capacity for renewables.

Yearly actions – Hydrogen producers

Similar to the power producers, we start out by calculating return on investment for the hydrogen producers:

$$\mathrm{ROI}_j = \frac{\sum_{n=0}^{N_{E,j}} Y_{E,n}}{\sum_{n=0}^{N_{E,j}} I_{E,n}} \quad \text{Eq. 39}$$

Where $N_{E,j}$ is the number of electrolyzers of hydrogen producer j, $I_{E,n}$ is the investment costs of electrolyzers n, and $Y_{E,n}$ is the earned cashflow of electrolyzer n in the current year. The earned cashflow $Y_{E,n}$ of electrolyzer n is the difference between benefits from selling hydrogen $B_{E,n}$ and electricity costs $C_{E,n}$:

$$Y_{E,n} = B_{E,n} - C_{E,n} \quad \text{Eq. 40}$$

Where the benefits $B_{E,n}$ are:

$$B_{E,n} = \sum_{d=1}^{365} p_{H_2} u_E(d) \eta_E A_{E,n} \quad \text{Eq. 41}$$

Where p_{H_2} is the current hydrogen price, $u_E(d)$ is the utilization of electrolyzers for day d, η_E is the efficiency of electrolyzers, and $A_{E,n}$ is the capacity of electrolyzer n. We can calculate the electricity costs by:

$$C_{E,n} = \sum_{d=1}^{365} p_{elc}(d) u_E(d) A_{E,n} \quad \text{Eq. 42}$$

Where $p_{elc}(d)$ is the electricity price for day d. With the return on investment ROI_j of hydrogen producer j. Now we can calculate the change in the investment threshold $\Delta\varphi_j$ for the hydrogen producer j:

$$\Delta\varphi_j = -\Delta\varphi_{max,j} * \tanh\left(ln\left(\frac{\mathrm{ROI}_j}{\mathrm{ROI}_{target,j}}\right)\right) \quad \text{Eq. 43}$$

Where $\Delta\varphi_{max,j}$ is the maximum change possible for hydrogen producer j, and $\mathrm{ROI}_{target,j}$ is the target return of investment for hydrogen producer j, at which the hydrogen producer achieves profitability. We can calculate this by setting the net present value $\mathrm{NPV}_{E,j}$ of an electrolyzer of hydrogen producer j equal zero and then solving for the necessary return on investment:

$$\mathrm{NPV}_{E,j} \stackrel{!}{=} 0 \quad \text{Eq. 44}$$

We can calculate the net present value $\mathrm{NPV}_{E,j}$ as follows for a constant cashflow Y_j of hydrogen producer j:

$$\mathrm{NPV}_{E,j} = -I_E + \frac{Y_j}{\mathrm{CRF}_E} \quad \text{Eq. 45}$$

Where I_E is the investment costs for an electrolyzer and the capital recovery factor CRF_E for an electrolyzer. We can calculate the capital recover factor CRF_E for an electrolyzer with the internal discount rate r, and T_E the lifetime of an electrolyzer.

$$\mathrm{CRF}_E = \frac{r}{1-(1+r)^{-T_E}} \quad \text{Eq. 46}$$

With Eq. (45) and Eq. (46), we can solve Eq. (44) for the target return on investment $\mathrm{ROI}_{target,j}$:

$$-I_E + \frac{Y_j}{\mathrm{CRF}_E} \overset{!}{=} 0 \quad \text{Eq. 47}$$

$$I_E = \frac{Y_j}{\mathrm{CRF}_E} \quad \text{Eq. 48}$$

$$\frac{Y_j}{I_E} = \mathrm{CRF}_E \quad \text{Eq. 49}$$

$$\mathrm{ROI}_{target,j} = \mathrm{CRF}_E \quad \text{Eq. 50}$$

The investment threshold $\varphi_j(t)$ of hydrogen producer j for year t can then be updated by:

$$\varphi_j(t) = \varphi_j(\mathrm{t}-1) + \Delta\varphi_j \quad \text{Eq. 51}$$

However, the hydrogen producer's individual investment threshold has a lower limit representing the maximum appetite for strategic investment of the hydrogen producer:

$$\varphi_j(t) \geq \varphi_{j,0}\left(1 - \frac{A_{E,cum}}{\alpha_j A_{E,target}}\right) \quad \text{Eq. 52}$$

Here, $\varphi_{j,0}$ is the investment threshold at initialization of hydrogen producer j, $A_{E,cum}$ is the cumulative electrolyzer capacity, $A_{E,target}$ is the political target for cumulative electrolyzer capacity and α_j represents the individual risk tolerance of hydrogen producer j.

Since there is no guarantee that hydrogen producers can buy an electrolyzer, we need to calculate the willingness to pay for electrolyzers. We can calculate the willingness to pay for an electrolyzer by setting the ratio of net present value of a new electrolyzer $\mathrm{NPV}_{E,j}$ and its investment cost $I_{E,j}$ equal to the current investment threshold $\varphi_j(t)$ of hydrogen producer j:

$$\varphi_j(t) \overset{!}{=} \frac{\mathrm{NPV}_{E,j}}{I_{E,j}} \quad \text{Eq. 53}$$

For the net present value of the new electrolyzer $\mathrm{NPV}_{E,j}$ a constant cashflow Y_j is assumed:

$$NPV_{E,j} = -I_{E,j} + \frac{Y_j}{\mathrm{CRF}_E} \quad \text{Eq. 54}$$

The constant cashflow Y_j is equal to the capacity of the new electrolyzer A_E times the specific average cashflow y_j of the hydrogen producer j in the current year.

$$Y_j = y_j A_E \quad \text{Eq. 55}$$

Where the specific average cashflow is based on the benefits $B_{E,n}(t)$, electricity costs $C_{E,n}(t)$ in the current year t and capacities $A_{E,n}$ of all electrolyzers of hydrogen producer j:

$$y_j = \frac{\sum_{n=0}^{N_{E,j}} B_{E,n}(t) - C_{E,n}(t)}{\sum_{n=0}^{N_{E,j}} A_{E,n}} \quad \text{Eq. 56}$$

We can calculate the benefits according to Eq. (41) and the electricity costs to Eq. (42). The investment costs $I_{E,j}$ for the new electrolyzer can be expressed as the specific willingness to pay $w_{E,j}$ of hydrogen producer j times the capacity of the new electrolyzer A_E:

$$I_{E,j} = w_{E,j} A_E \quad \text{Eq. 57}$$

Using Eq. (54), Eq. (55) and Eq. (57), we can solve Eq. (53) for the specific willingness to pay for a new electrolyzer $w_{E,j}$ by hydrogen producers j:

$$\varphi_j(t) = \frac{\mathrm{NPV}_{E,j}}{I_{E,j}} \quad \text{Eq. 58}$$

$$\varphi_j(t) I_{E,j} = -I_{E,j} + \frac{Y_j}{\mathrm{CRF}_E} \quad \text{Eq. 59}$$

$$\left(1 + \varphi_j(t)\right) I_{E,j} = \frac{Y_j}{\mathrm{CRF}_E} \quad \text{Eq. 60}$$

$$w_{E,j}A_E = \frac{y_j A_E}{\mathrm{CRF}_E\left(1+\varphi_j(t)\right)} \quad \text{Eq. 61}$$

$$w_{E,j} = \frac{y_j}{\mathrm{CRF}_E\left(1+\varphi_j(t)\right)} \quad \text{Eq. 62}$$

The hydrogen producer can then try to buy electrolyzers in order of their specific willingness to pay in descending order. The hydrogen producer will choose the electrolyzer manufacturer who can fulfill their demand in the best way. For this the hydrogen producer selects the electrolyzer manufacturer with the lowest production costs and difference between the asked and provided capacity:

$$\min\left(\omega_{c,j}\frac{c_{E,k}}{c_{E,max}} + \omega_{A,j}\frac{\Delta A_{E,k}}{\Delta A_{E,max}}\right) \text{ for } k = 0\ldots N_{EP} \quad \text{Eq. 63}$$

Where N_{EP} is the number of electrolyzer manufacturers, $c_{E,k}$ is the specific production costs of electrolyzer manufacturer k, $c_{E,max}$ is the maximum of specific production costs of all electrolyzer manufacturers:

$$c_{E,max} = \max\left(c_{E,k}\right) \quad \text{for } k = 0\ldots N_{EP} \quad \text{Eq. 64}$$

$\Delta A_{E,k}$ is the difference between the capacity asked by the hydrogen producer and the maximum capacity that the electrolyzer manufacturer can produce, if they cannot produce the asked capacity. $\Delta A_{E,max}$ is the maximum of this value of all electrolyzer manufacturers:

$$\Delta A_{E,max} = \max\left(\Delta A_{E,k}\right) \text{ for } k = 0\ldots N_{EP} \quad \text{Eq. 65}$$

$\omega_{c,j}$ and $\omega_{A,j}$ are the weights at which hydrogen producer j values these factors:

$$\omega_{c,j} + \omega_{A,j} = 1 \quad \text{Eq. 66}$$

After finding the electrolyzer manufacturer k which fits best the demand of the hydrogen producer j, we can calculate the actual specific price $p_{E,jk}$ at which the electrolyzer is sold:

$$p_{E,jk} = c_{E,k} + \beta\left(w_{E,j} - c_{E,k}\right) \quad \text{Eq. 67}$$

Where β is the bargaining factor, that is based on the ratio of maximum demand for electrolyzers $A_{E,D}$ and the maximum supply of electrolyzers $A_{E,S}$:

$$\begin{aligned} \beta &= \frac{1}{2}\frac{A_{E,D}}{A_{E,S}} \quad \text{for } \frac{A_{E,D}}{A_{E,S}} \le 1 \\ \beta &= 1 - \frac{1}{2}\frac{A_{E,S}}{A_{E,D}} \quad \text{for } \frac{A_{E,D}}{A_{E,S}} > 1 \end{aligned} \quad \text{Eq. 68}$$

We define the maximum demand for electrolyzers $A_{E,D}$ as:

$$A_{E,D} = \sum_{j=0}^{N_{HP}} A_{E,j} \quad \text{Eq. 69}$$

Where N_{EP} is the number of hydrogen producers, and $A_{E,j}$ is the capacity for a new electrolyzer by hydrogen producer j. We can calculate the maximum supply for electrolyzers $A_{E,S}$ by:

$$A_{E,S} = \sum_{p=0}^{N_F} A_{F,p} \quad \text{Eq. 70}$$

Where N_F is the number of factories for electrolyzer production and $A_{F,p}$ is the manufacturing capacity of factory p.

If a positive investment decision is made in one year and an electrolyzer could be bought, we can calculate the capacity for electrolyzer A_E in the next year as follows:

$$A_E(t+1) = 1.25 {}^* A_E(t) \; for \;\; A_E(t) < A_{E,max} \quad \text{Eq. 71}$$

Where $A_{E,max}$ is the maximum capacity of electrolyzers.

Yearly actions – Electrolyzer manufacturer

Finaly, we can calculate the return of investment ROI_k for the electrolyzer manufacturer k:

$$\mathrm{ROI}_k = \frac{Y_k}{\sum_{p=0}^{N_{F,k}} I_{F,p}} \quad \text{Eq. 72}$$

Where $N_{F,k}$ is the number of factories for electrolyzer production of electrolyzer manufacturer k, $I_{F,p}$ is the investment costs of factory for electrolyzer production p, and Y_k is the earned cashflow of electrolyzer manufacturer k in the current year. We can calculate the earned cashflow Y_k of electrolyzer manufacturer k as the difference between the price and production costs times the electrolyzer capacity for each sale of electrolyzer:

$$Y_k = \sum_{s=0}^{N_{S,k}} (p_{E,s} - c_{E,s}) A_{E,s} \quad \text{Eq. 73}$$

Where $N_{S,k}$ is the total number of sales of electrolyzer manufacturer k in the current year, $p_{E,s}$ is the specific price of the electrolyzer for sale s, $c_{E,s}$ is the specific production costs of the electrolyzer for sale s, and $A_{E,s}$ is the capacity of the electrolyzer for sale s.

With the return of investment ROI_k we can calculate the change in the investment threshold $\Delta\varphi_k$ for the electrolyzer manufacturer k:

$$\Delta\varphi_k = -\Delta\varphi_{max,k} * \tanh\left(ln\left(\frac{\mathrm{ROI}_k}{\mathrm{ROI}_{target,k}}\right)\right) \quad \text{Eq. 74}$$

Where $\Delta\varphi_{max,k}$ is the maximum change possible for electrolyzer manufacturer k, and $ROI_{target,k}$ is the target return of investment for electrolyzer manufacturer k at which the power producer achieves profitability. We can determine this by setting the net present value $NPV_{F,k}$ of a factory for electrolyzer production of electrolyzer manufacturer k equal zero and then solving for the necessary return on investment:

$$\mathrm{NPV}_{F,k} \overset{!}{=} 0 \quad \text{Eq. 75}$$

We can calculate the net present value $NPV_{F,k}$ as follows for a constant cashflow Y_k for power producer k:

$$\mathrm{NPV}_{F,k} = -I_F + \frac{Y_k}{\mathrm{CRF}_F} \quad \text{Eq. 76}$$

Where I_F is the investment costs for a factory for electrolyzer production and the capital recovery factor CRF_F for a factory for electrolyzer production. We can calculate this with the internal discount rate r, and T_F the lifetime of a factory for electrolyzer production.

$$\mathrm{CRF}_F = \frac{r}{1-(1+r)^{-T_F}} \quad \text{Eq. 77}$$

We can use Eq. (76) and Eq. (77) to solve Eq. (75) for the target return on investment $\mathrm{ROI}_{\mathrm{target,k}}$:

$$-I_F + \frac{Y_k}{\mathrm{CRF}_F} \overset{!}{=} 0 \quad \text{Eq. 78}$$

$$I_F = \frac{Y_k}{\mathrm{CRF}_F} \quad \text{Eq. 79}$$

$$\frac{Y_k}{I_F} = \mathrm{CRF}_F \quad \text{Eq. 80}$$

$$\mathrm{ROI}_{target,k} = \mathrm{CRF}_F \quad \text{Eq. 81}$$

We can then update the investment threshold $\varphi_k(t)$ of electrolyzer manufacturer k for year t:

$$\varphi_k(t) = \varphi_k(\mathrm{t}-1) + \Delta\varphi_k \quad \text{Eq. 82}$$

Similar to the hydrogen producers, the electrolyzer manufacturer's individual investment threshold has a lower limit representing the maximum appetite for strategic investment of the electrolyzers producer:

$$\varphi_k(t) \geq \varphi_{k,0}\left(1 - \frac{A_{E,cum}}{\alpha_k A_{E,target}}\right) \quad \text{Eq. 83}$$

Here, $\varphi_{k,0}$ is the investment threshold at initialization of electrolyzer manufacturer k, $A_{E,cum}$ is the cumulative electrolyzer capacity, $A_{E,target}$ is the political target for cumulative electrolyzer capacity and α_k represents the individual risk tolerance of electrolyzers producer k.

The electrolyzer manufacturer then makes an investment decision based on the expected net present value $\mathrm{NPV}_{F,k}$ of a new factory for electrolyzer production, investment costs I_F and the updated investment threshold $\varphi_k(t)$:

$$\varphi_k(t) \leq \frac{\mathrm{NPV}_{F,k}}{I_F} \quad \text{Eq. 84}$$

The net present value $\mathrm{NPV}_{F,k}$ of the new factory is based on the specific investment costs for factories for electrolyzer production i_F, the capital recovery factor for factories for electrolyzer production CRF_F, the capacity of the new factory A_F and the specific cashflow y_k, which is assumed to be constant:

$$\mathrm{NPV}_{F,k} = -i_F A_F + \frac{y_k A_F}{\mathrm{CRF}_F} \quad \text{Eq. 85}$$

We assume that the specific cashflow y_k is equal to the specific average cashflow of the existing assets of electrolyzer manufacturer k:

$$y_k = \frac{Y_k}{\sum_{p=0}^{N_{F,k}} A_{F,p}} \quad \text{Eq. 86}$$

Where $N_{F,k}$ is the number of factories of electrolyzer manufacturer k, Y_k is the cashflow of electrolyzer manufacturer k earned in the current year t, and $A_{F,p}$ is the capacity of factory p.

If a positive investment decision is made in one year, we can calculate the increase in capacity for the next factory A_F as follows:

$$A_F(t+1) = 1.25 * A_F(t) \; for \;\; A_F(t) < A_{F,max} \qquad \text{Eq. 87}$$

Where $A_{F,max}$ is the maximum capacity of factories for electrolyzer production.

B. Appendix B.

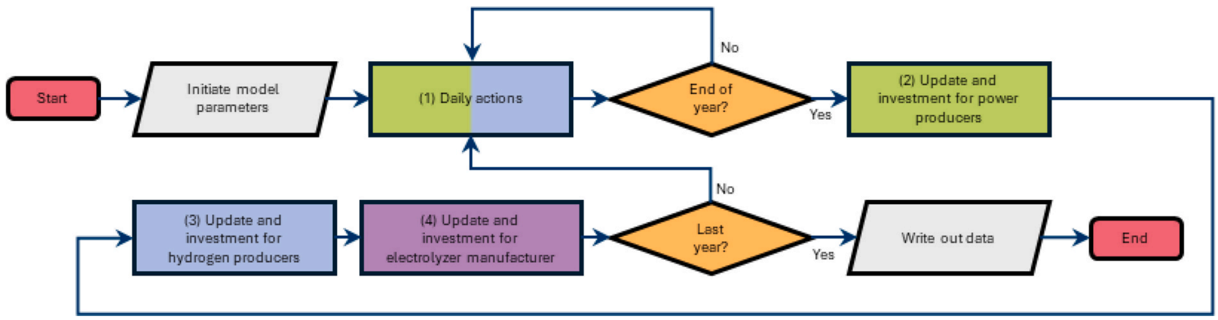

Fig. B 1. Flow chart of an overview for the model.

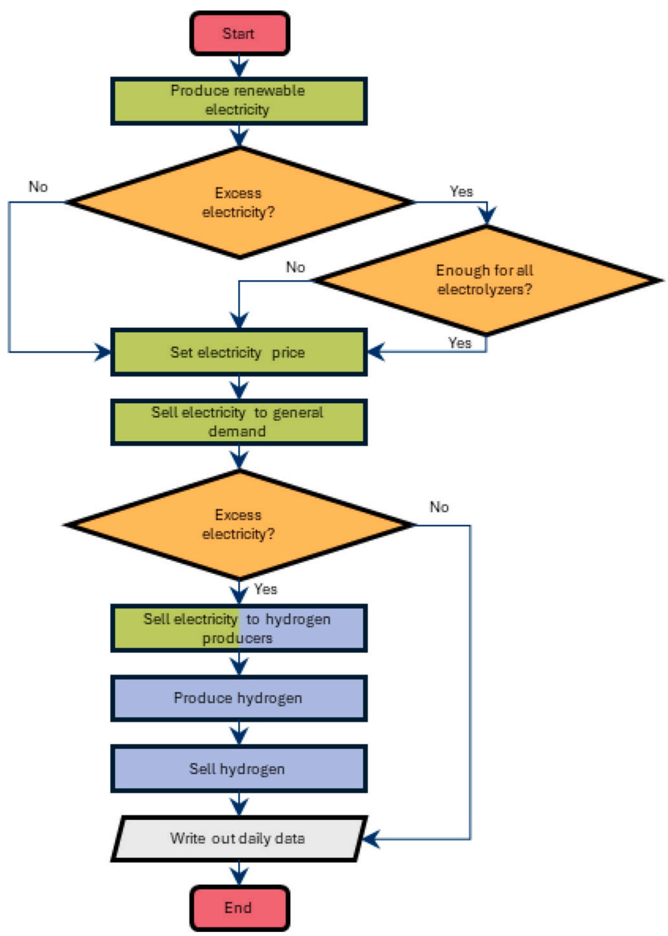

Fig. B 2. Flow chart for overview of daily actions.

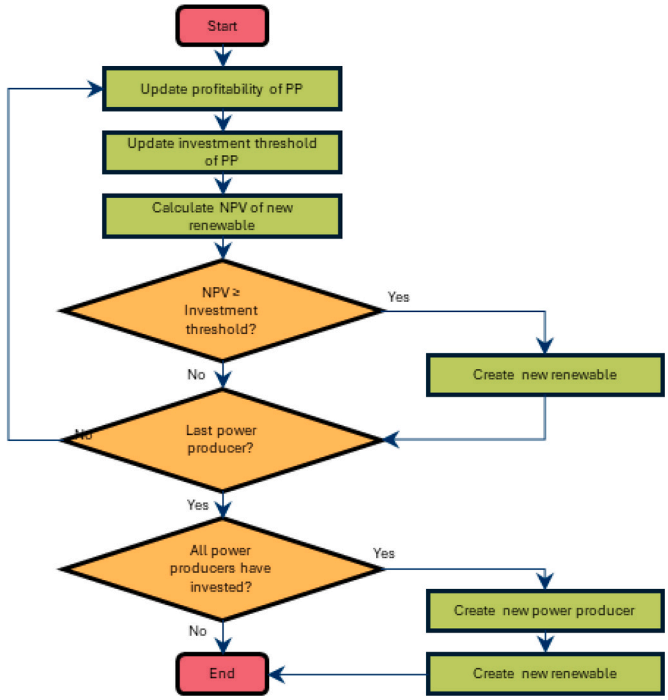

Fig. B 3. Flow chart for investment decisions power sector.

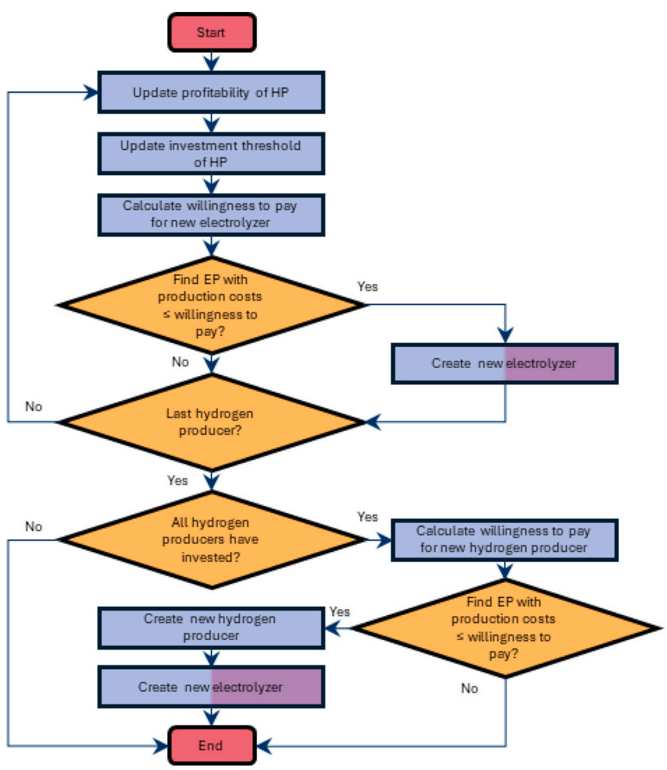

Fig. B 4. Flow chart for investment decisions hydrogen sector.

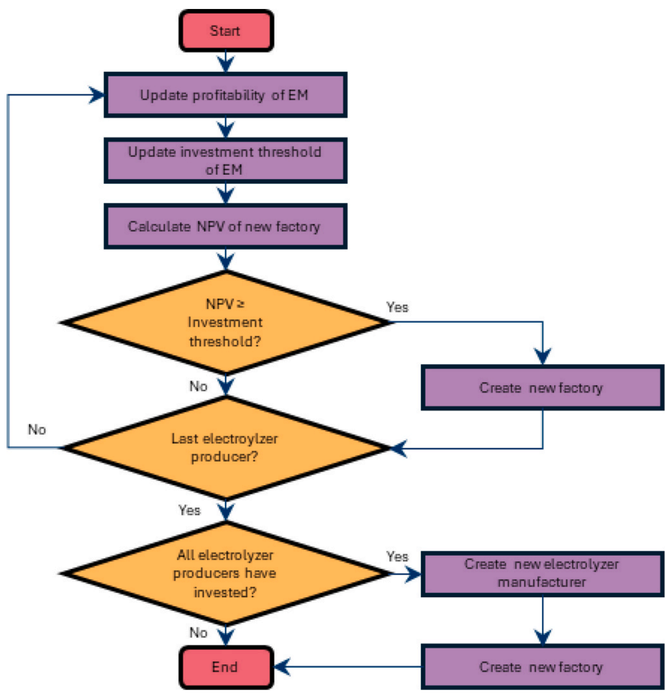

Fig. B 5. Flow chart for investment decisions electrolyzer manufacturing sector.

C. Appendix C.

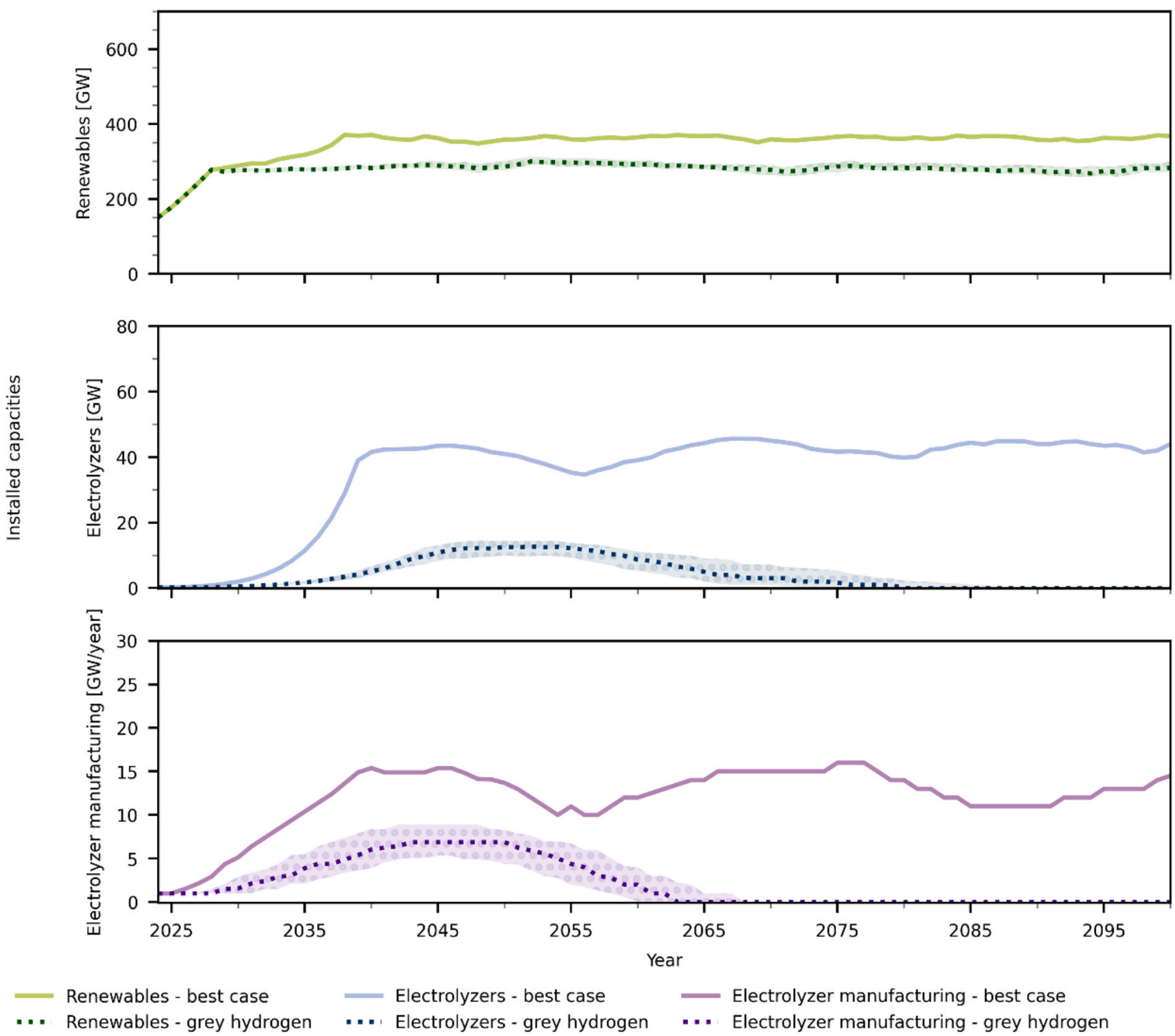

Fig. C 1. Installed capacities for the "grey hydrogen" scenario until 2100 showing the collapse of the green hydrogen industry.

D. Appendix D.

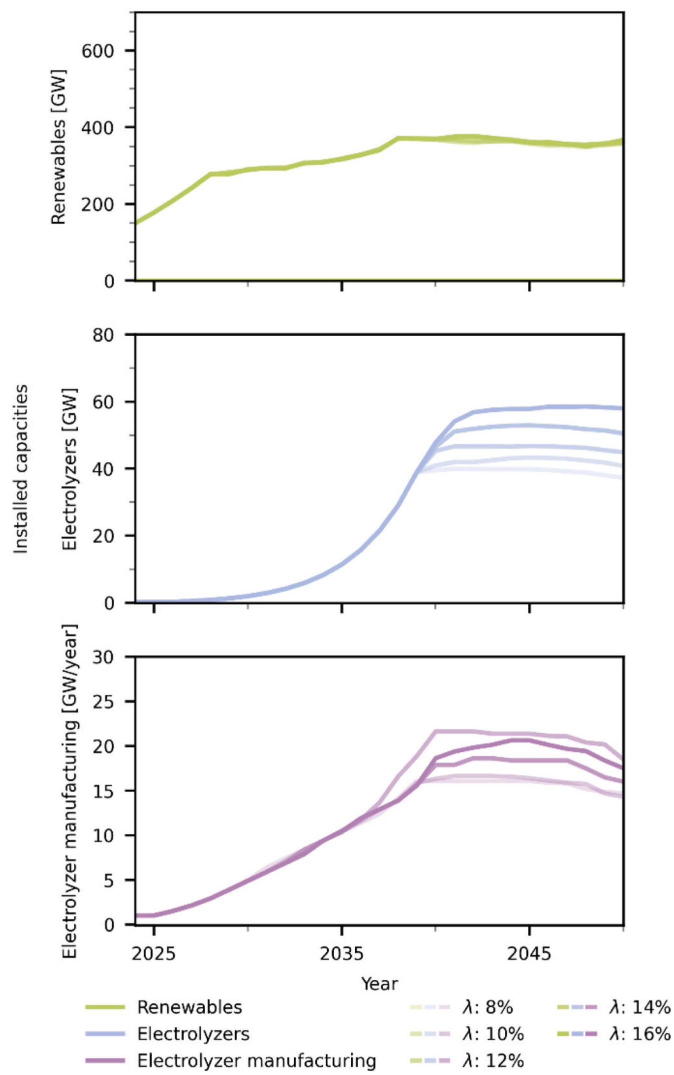

Fig. D 1. Installed renewables capacities (top), electrolyzers capacities (middle) and manufacturing capacities for electrolyzers (lower) for different learning rates.

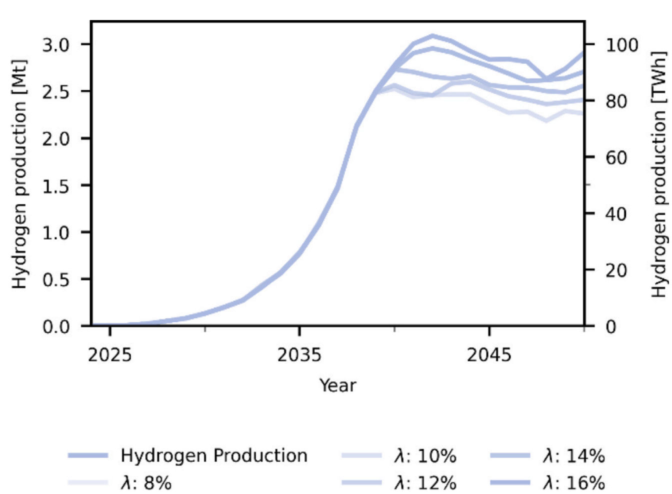

Fig. D 2. Hydrogen production for each year for different learning rates.

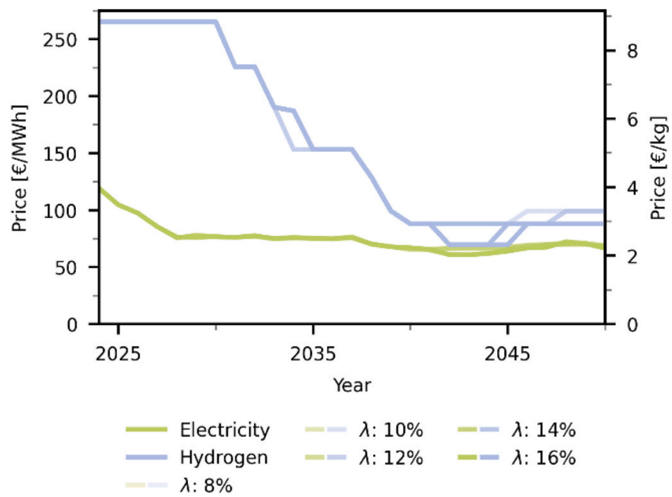

Fig. D 3. Comparison of electricity price for the non-electrolytic demand (green) and green hydrogen price (blue) for different learning rates.

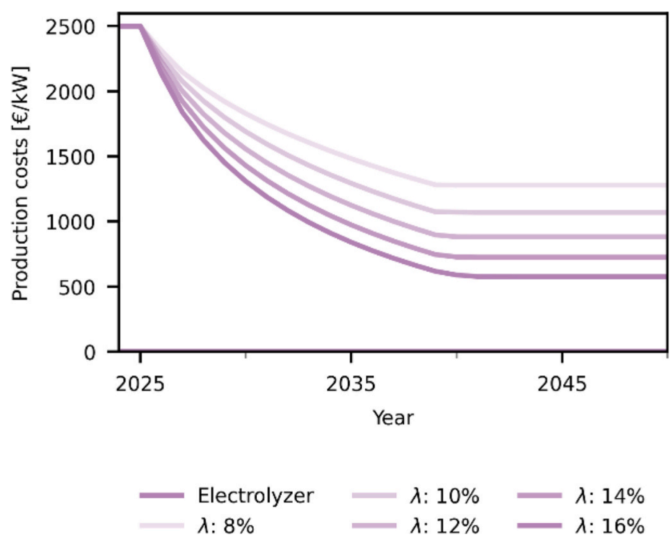

Fig. D 4. Minimal electrolyzer production costs at which the cheapest electrolyzer manufacturer can produce each year for different learning rates.

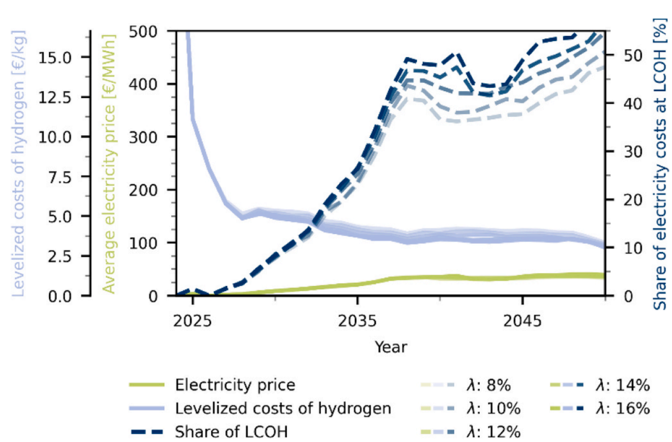

Fig. D 5. Comparison of electricity costs for hydrogen producers (green) and the average levelized costs of hydrogen (blue). The share of the electricity costs on the LCOH are shown with a dashed line (dark blue) for different learning rates.

E. Appendix E.

For validation, we simulated the power sector for the period from 2000 to 2024. In our model, we set the initial installed capacity for renewable energy to 6.2 GW, corresponding to the historical value in 2000 [111]. Additionally, we reduced the initial number of power producers to reflect the fewer operators at that time [112]. We also limited the initial size of renewable energy projects to 300 MW and reduced the growth rate of projects, as renewable energy projects were generally smaller in the past [113,114]. We compared the development of installed renewable capacity, renewable electricity production, and their share in total electricity production. Our results have a mean absolute percentage error of 16.2 % for the installed renewable capacity, 15.7 % for the share of renewables in electricity production, and 10.6 % for renewable electricity production compared to the historical data.

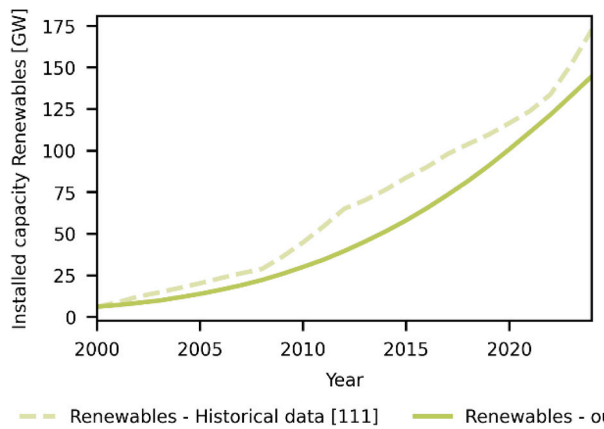

Fig. E 1. Installed renewables capacities of our model (solid) and historical data (dashed) [111].

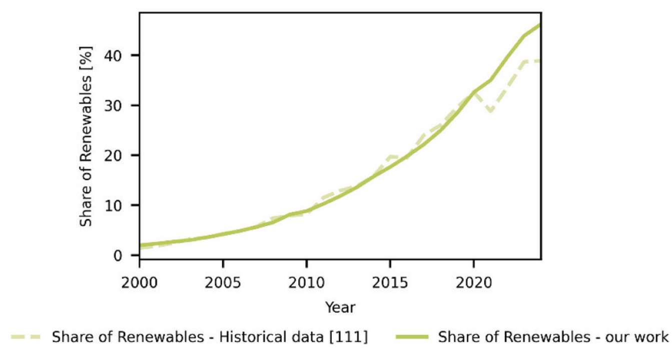

Fig. E 2. Share of renewables in electricity production of our model (solid) and historical data (dashed) [111].

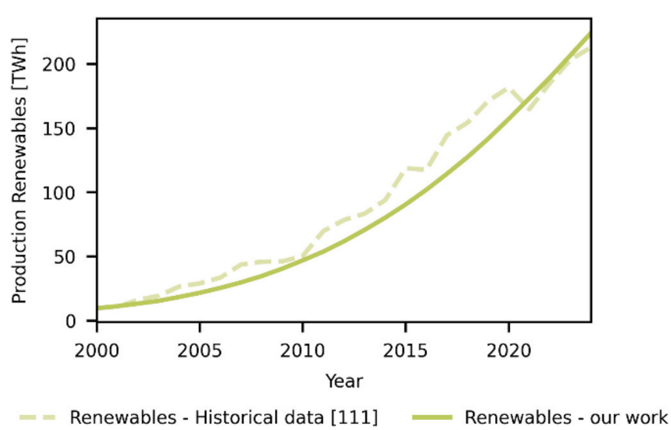

Fig. E 3. Renewable electricity production of our model (solid) and historical data (dashed) [111].

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