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Green hydrogen – How grey can it be?

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Abstract

Low-carbon hydrogen is expected to play a key role in the European energy transition. The production of hydrogen using electricity in an electrolysis process is a promising route. However, depending on the origin of the electricity, hydrogen production is associated with different carbon emissions and costs. While a strict coupling of renewable energies to electrolysers ensures the 'greenness' of the product, it likely leads to higher production costs. On the contrary, procuring electricity freely at power markets unleashes the flexibility of electrolysers, allowing them to benefit from price signals and possibly reducing production costs. However, the carbon intensity in both the power system and the resulting hydrogen product might rise. Consequently, there is a trade-off between environmental integrity and economic viability which affects social welfare and the decarbonisation process. By applying an electricity market model, we assess the impact of various regulatory options for the operation of electrolyser systems on social welfare and carbon emissions. These options are based on the three dimensions proposed in the ongoing regulatory discussions: (1) the origin of the sourced electricity, (2) the temporal correlation of the production of hydrogen and renewable electricity and (3) their spatial correlation. For the case of Germany in 2030, we find that the most environmentally friendly regulation reduces CO_2 emissions by 4.7 Mt and the best economic outcome results in 0.9 Billion EUR of welfare gains. While too stringent regulation on the spatial dimension is not recommended, the various advantages of relatively strict requirements in the temporal dimension (e.g., decline in CO_2 emissions, financial exoneration of consumers, reduction in natural gas demand) exceed their comparably moderate economic disadvantages. Moreover, we find that with a progressing energy transition, the need for such regulation diminishes, as electricity from renewable energies represents both the best economic and the best environmental option, so that the observed trade-off disappears.

Keywords

Electrolytic hydrogen, Regulation, Electricity market, Welfare

Contents

1. Introduction

With the European Green Deal, announced at the end of 2019, the EU committed itself to climate neutrality by 2050. This ambition requires a radical restructuring of today's energy supply. In the past two decades the deployment of renewable energies (RES) has demonstrated their ability to contribute to this goal. However, due to their variability and the absence of sufficient viable large-scale storage, new challenges in the operation of the power system occur, making a simple further upscaling of renewable capacity for decarbonisation purposes difficult. Furthermore, there are various sectors in the economy such as the industry and the transport sector where the direct replacement of fossil energy with renewable electricity is either not viable or just not possible. They are also referred to sectors that are 'hard-to-abate'. Hydrogen is an energy carrier that shows promising possibilities to contribute to the decarbonisation of those sectors but also to the wider economy alongside direct electrification. Its chemical characteristics offer strengths that complement direct electrification well. This makes hydrogen a promising element in the decarbonisation process. However, one key requirement for the use of hydrogen as an energy carrier in future energy systems is that its use needs to bring a significant reduction of CO_2 emissions (Velazquez Abad and Dodds 2020). As hydrogen does not exist in pure nature, it needs to be produced. Historically, fossil fuels such as natural gas and coal were mainly used to produce it. Its production has been leading to substantial carbon emissions (IEA 2020). However, there are two promising production routes that can provide hydrogen without or at low CO_2 emissions. The first one is hydrogen from natural gas produced via methane reforming processes (SMR) that are combined with carbon capture and storage facilities (CCS) which extract and store the CO_2 before it is released to the atmosphere. The hydrogen produced via this pathway is also referred to as 'blue' hydrogen. Electrolytic hydrogen represents another path. Electricity is used in the electrolysis process to split water into its elements oxygen and hydrogen. The electrolysis process is considered a sector-coupling technology that links the electricity system with other sectors. It could therefore help to provide flexibility to the energy system and hence, to facilitate the integration of renewable energies. The possibilities and the potential of low-carbon hydrogen to contribute to the decarbonisation of the economy has also been acknowledged by the EU. The European hydrogen strategy as well as various national hydrogen strategies have been released in recent years and assign low-carbon hydrogen a pivotal role in the energy transition. (EU Commission 2020) Consequently, while hydrogen has played so far only a minor role in the energy sector, mainly as feedstock in the industry, consumption is expected to increase rapidly in the coming decades which is also shown by projections of various studies. (Deloitte 2021; FCH Joint Undertaking 2019)

Blue hydrogen was considered to play a key role during the ramp-up phase of the low-carbon hydrogen economy in the coming decade due to favourable economics in short-term. However, the Russian invasion of Ukraine has put this strategy in question. The EU aims at quickly reducing natural gas imports from Russia and targets to stop all energy imports completely as soon as possible. (European Commission 2022) However, due to its high dependence on Russian natural gas, both the EU's natural gas demand must decrease, and significant volumes need to be replaced by other sources. However, depletion of domestic resources and limited import options from other parts of the world suggest that available natural gas volumes in the EU are likely to remain constrained for the remainder of the 2020s. These are preferably used to satisfy existing demand and less for the use in new applications such as the production of blue hydrogen. Consequently, the alternative route, the production of electrolytic hydrogen is likely to gain importance at an earlier stage.

The production of electrolytic hydrogen requires electricity. Depending on the origin, this electricity has a different CO_2 content. Moreover, the individual available electricity sources are characterised by different generation costs as well as different availabilities, both of which have an impact on the production costs of hydrogen. This creates a 'dilemma'.

While electricity from variable renewable energies (RES) such as solar PV and wind energy does not have direct carbon emissions, electricity from fossil sources is partly associated to significant direct carbon emissions. However, the availabilities of variable renewable energies remain low compared to dispatchable generators and are subject to seasonal differences among the individual technologies and resources. Consequently, there is a trade-off between environmental integrity and economic viability:

- Benefitting from higher availability factors of grid electricity lowers costs but might lead to higher carbon emissions;
- Relying entirely on variable renewable energies ensures the reduction of carbon emissions but results in overall higher costs.

Consequently, prioritising environmental aspects might hinder the development of the hydrogen economy through higher costs, while focusing on the economic viability might increase carbon emissions and counteract the decarbonisation process.

Currently, policymakers and regulators frame the regulatory basis for the production of electrolytic hydrogen and the integration of electrolysers in the energy system.[1] The successful development of a low-carbon hydrogen economy is important to not only meet the overarching decarbonisation goal in a timely and socially acceptable manner but also to ensure competitiveness of the EU industry and to maintain a technology leadership in the sector. Therefore, it is important to assess regulations on both their environmental and their economic impact. This study contributes to the discussion on the introduction of appropriate regulatory measures to address the trade-off between environmental integrity and economic viability in the production of electrolytic hydrogen.

The remainder of the work is structured as follows: in Section 2 we give an overview of the relevant literature and discuss the current thinking on the regulation of electrolytic hydrogen. In Section 3 both the methodology and the developed model are described. This is followed by an introduction of the case study and the related data (Section 4). Next, in Section 5 the results are presented, which are then discussed in Section 6. At the end a conclusion of the analysis is given (Section 7).

2. Background and literature review

The interest in electrolytic hydrogen as a widespread energy carrier has been a topic at various points in time over the past decades so that the subject has already been studied from various angles. However, in the past, its breakthrough failed mainly due to its missing economic viability. With the binding commitment to carbon reduction targets[2], the significant decline in the costs of renewable electricity[3], and the official acknowledgement of its possibilities and its potential in the energy transition[4], the interest in electrolytic hydrogen has increased drastically over the past years. As part of this new wave, various recent studies focus on the production of electrolytic hydrogen from different perspectives. Roach and Meeus (2020) for example assess the welfare and prices effects of electrolyser systems that operate at the intersection between electricity and natural gas systems. They use a model formulated as a complementary problem and find that there is an aligned incentive for electrolyser systems in both the electricity and the natural gas sector. However, their outcomes also show that a welfare optimised system configuration results in a loss for the electrolyser unit. Another study that focuses on the effect of electrolyser systems as sector coupling technology between energy markets was conducted by Li and Mulder (2021). The authors studied the interaction of electrolysers between the electricity and the expected hydrogen market. They find that electrolyser systems can provide valuable flexibility to the electricity sector. However, they conclude that efficiency improvements and cost reductions of electrolyser systems as well as higher CO_2 prices are necessary to result in a positive economic value for electrolysers. Other studies focused rather on the integration of electrolysers in the power

1 Renewable Energy Directive II – RED II
2 United Nations Paris Agreement - https://www.un.org/en/climatechange/paris-agreement
3 (IRENA 2020)
4 (EU Commission 2020) and (German Federal Ministry of Economics and Technology 2020)

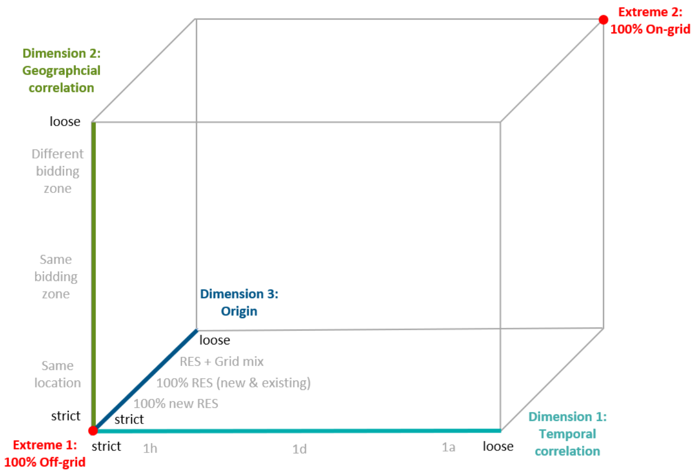
sector and their interaction with it. Ruhnau (2020) for example assessed whether the production of electrolytic hydrogen can stabilise the market value of renewable energies. The author applied an electricity market model and found that flexible operating electrolyser systems counteract the cannibalisation of the market value of renewable energies. Stöckl et al. (2021) conducted another study on the interaction of electrolyser systems with the power sector. They also used an electricity market model with a simplified integrated hydrogen supply chain optimisation to study the impact of various parameters such as the penetration of renewable energies and the hydrogen demand level on the optimal system design. They find that there is a trade-off between energy efficiency and temporal flexibility. While for lower shares of renewables the energy efficiency in the hydrogen supply structure is more important, for higher shares of renewables the temporal flexibility of electrolysers gains in importance. In the study of vom Scheidt et al. (2022) the production of electrolytic hydrogen is assessed from a different angle. The authors analyse the effect of spatial price signals for the integration of electrolyser systems in single-price markets. They find that spatial signals are important instruments to avoid grid congestions and to reduce costs due to both avoided curtailments of renewable energies and reduced redispatch measures. The potential of electrolyser systems to facilitate the operation of the power system and hence, to reduce overall system costs was also shown by Xiong et al. (2021). In addition to the studies mentioned above, there are many more that analysed the production of electrolytic hydrogen with different emphases. However, most of the existing literature focuses on a cost optimised integration of electrolyser systems in the power system as well as on the interaction with it. Among others, previous studies assessed the hydrogen production costs and partially the impacts of the electrolytic hydrogen production on resulting carbon emissions. To summarise, they find that grid connected electrolysers can have a value for the power system, especially those with operating flexibility. However, previous studies did not distinguish with respect to the carbon intensity of the produced hydrogen and often use renewable or green hydrogen as synonym for electrolytic hydrogen regardless of the origin of the sourced electricity and its carbon content.

Following the regulatory discussions in the creation of a target-oriented taxonomy for the European energy transition, however, makes clear that electrolytic hydrogen cannot be considered a homogenous good. Instead, distinctions of electrolytic hydrogen based on associated carbon content are discussed such as the categorisation into low-carbon and renewable hydrogen. This calls for the implementation of regulations to provide an official basis for the distinction. Velazquez Abad and Dodds (2020) discuss the topic qualitatively. The authors list the characterisation of green hydrogen in existing standardisation approaches. They point out that these differ substantially in the way how green hydrogen is characterised. The authors conclude that there is so far no common understanding which would facilitate informed decision making for investments. The effects of possible regulatory aspects for the production of electrolytic hydrogen have so far not been studied in the literature except for a first attempt by Schlund and Theile (2021). The authors assess for the case of German in 2020 the effect of various regulations with respect to the ‘simultaneity’ aspect. This aspect describes and defines the period in which renewable electricity is generated and sourced to produce hydrogen. They applied an optimisation model, that represents a profit-maximising electrolyser system. The model is combined with a Monte-Carlo simulation that mimics the electricity wholesale market under consideration of stochastically changing availabilities of wind generators.

They confirm the existence of the dilemma of electrolytic hydrogen and conclude that when putting in place regulation, policymakers must decide whether to prioritise the economic viability, which comes at the cost of additional carbon emissions, or the other way around. However, the effects of regulation on the overall system, the resulting carbon emissions and the corresponding changes in welfare have to the best of our knowledge not been addressed so far. This is also acknowledged by Schlund and Theile (2021), who indicated these aspects as further research directions.

However, studying this subject requires a better understanding of possible regulations. The ongoing discussions focus mainly on three regulatory aspects namely (1) the origin of the sourced electricity, as well as (2) the temporal and (3) the geographical correlation between generated renewable electricity and sourced electricity. (Frontier economics 2021) The first aspect, origin of the sourced electricity, refers to how the sourced electricity is generated. Often the word ‘additionality’ is mentioned in this context. It indicates that the sourced electricity must come from renewable energies that present an addition of renewable capacity to the overall power system. The second aspect, the temporal correlation, refers to what Schlund and Theile (2021) called ‘simultaneity’. It describes the timeframe in which the generated renewable electricity and the sourced electricity are balanced. Finally, the third aspect, the geographical correlation refers to the spatial relation between renewable facilities and the corresponding electrolyser systems. Each of the three aspects can be set to various states ranging from very strict to very loose requirements. Consequently, they can be considered as regulatory dimensions with different levels of stringency spanning a three-dimensional space, as illustrated in Figure 1.

Figure 1. Regulatory dimensions



The lower left corner represents the point where all dimensions are set to the strictest possible levels. In this case, the electricity must come from newly build renewable energies (strict origin) that are located at the same location as the electrolyser system (strict geographical correlation). Furthermore, the generated renewable electricity must be used directly (strict temporal correlation). This point can also be described as a 100% off-grid system, where there is (virtually) no connection to the wider electricity grid. In our study we refer to it as ‘extreme 1’. This strictest case can be relaxed on all three dimensions. While relaxations on the geographical correlation would allow for installations of renewables at a wider spatial scale such as somewhere in the same bidding zone or even in another one not restricted to the electrolyser location, relaxing the temporal correlation increases the timeframe in which the generated renewable electricity and the sourced electricity are balanced. The timeframe might increase from very short periods such as quarter-hourly or hourly, to longer ones such as daily, weekly, monthly, or even annually.

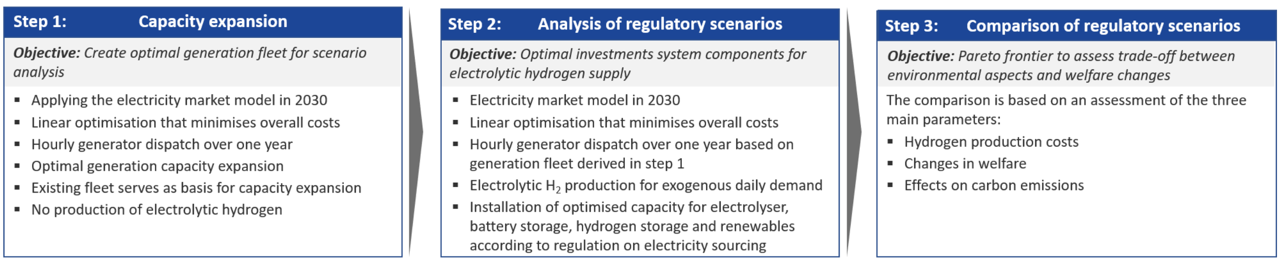
In these cases, it needs to be ensured that the sum of the generated renewable electricity matches the sum of the sourced electricity within the same period. Relaxations on the third dimension, the origin of the electricity, would loosen the requirements on where the electricity comes from. Possible relaxations might permit to use electricity of already existing renewables rather than only electricity from newly build ones. Allowing even for reduced shares of renewable electricity within the sourced electricity mix, might present an additional level of easing the constraints. The case where all three dimensions are relaxed at maximum is presented by the upper right corner. Since, in this case, there are no conditions attached to the origin of the electricity, there are neither any constraints on the temporal nor on the geographical correlation with the generation of renewable electricity. In this case the electricity can be sourced freely at the market. We refer to it as 'extreme 2' – 100% on-grid.

Within this study these three dimensions are used to assess various regulations for the electricity sourcing of electrolytic hydrogen. Each of the assessed regulation represents a different level of stringency. Our work aims to shed light on which regulation is beneficial in terms of the trade-off between environmental integrity and economic viability in the production of electrolytic hydrogen. We focus on the short-term implication of the regulations during the ramp-up phase of the hydrogen economy.

3. Methodology

To answer the research question, a quantitative approach is chosen, consisting of three consecutive steps (see Figure 2). The core of the analysis is to study the interaction between the production of electrolytic hydrogen and the operation of the power system. Therefore, an electricity market model is developed, which represents the electricity wholesale market. It enables to extract a variety of information on the development and the operation of generation units as well as the influence of additional electricity demand caused by the production of electrolytic hydrogen. A detailed description of the model is provided in the Appendix A.1.

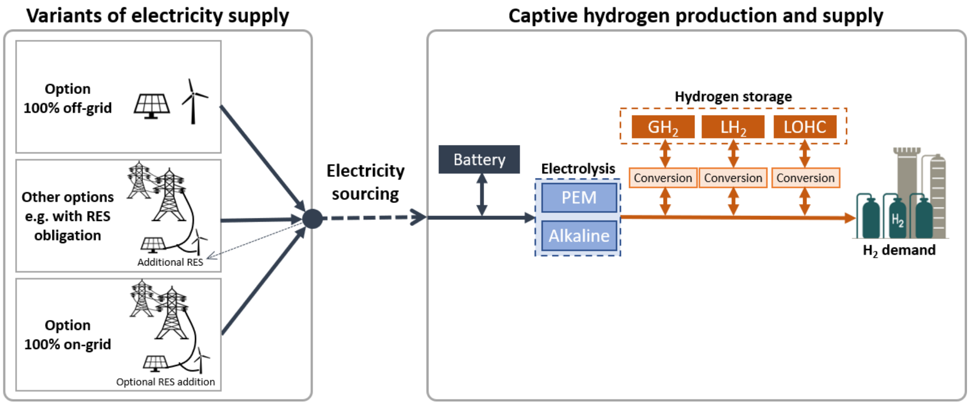
Figure 2. Overview about methodology



The first step, capacity expansion, serves to build the foundation of the analysis. In this step the electricity market model is applied in a capacity expansion mode, meaning that for the considered geographical scope the model can decide endogenously about the commissioning of new or the decommissioning of existing generation units. The decisions are based on the economic viability of the units. Within this step, we do not consider any production of electrolytic hydrogen. The first step aims at building an economically optimal generation fleet, that is then in the second step of the analysis confronted with an additional electricity demand through the production of electrolytic hydrogen.

In the second step of the analysis the electricity market model is applied again. However, this time, the focus is on the operation of the generation units and the changes to the power system caused by the introduction of hydrogen demand. The optimised generation fleet from the first step is used as input. Moreover, an exogenous daily hydrogen consumption is introduced, that needs to be supplied in a captive manner, meaning that the hydrogen is produced and processed near the final demand location. This stems from one of our key assumptions, namely that in the early ramp-up phase of the hydrogen economy, no meaningful hydrogen infrastructure is available that could be used to transport hydrogen in large quantities over considerable distances. In this second step, the electricity market model can invest in all system components that are required to supply the hydrogen demand in a least-cost manner and to size their respective capacities. This includes the storage of electricity in batteries, electrolyser systems that convert electricity to hydrogen and facilities to store hydrogen. The whole setup of investment possibilities and their arrangement is illustrated in Figure 3. Furthermore, as the objective of the second step is to analyse constraints through regulation on the electricity sourcing for the hydrogen production, the model is also allowed to invest in additional renewable capacity. However, depending on the analysed regulation, further conditions (e.g., on the spatial correlation to the demand location) might be set to constrain their installation. The market model represents a perfectly competitive electricity market setup with all players acting in a profit-maximising manner. Consequently, both the dispatch decisions of generators in the power market and all investments in hydrogen supply components as well as their operation result in optimal supply systems that minimise hydrogen production costs.

Figure 3. Scheme of hydrogen supply structure



Based on the introduced regulatory dimensions, various possible regulations for the electricity sourcing are analysed within this second step. In the extreme case 1, the regulatory case of a 100% off-grid configuration, the model can invest only in renewable capacity near the hydrogen demand location. There is no grid connection considered that would enable an interaction of the hydrogen system with the wider power system. In the extreme case 2, unrestricted 100% on-grid system, the hydrogen supply system is linked with the power market and can source electricity freely from it. However, depending on the viability of renewable energies, additional renewable capacities might be installed by the model without having obligations to do so. Between the two extreme cases, a variety of additional potential regulations can be found within the cube spanned by the three discussed regulatory dimensions (see Figure 1). Relaxations on the geographical correlation are represented within the model through constraints that allow for installations of renewable energies at different spatial levels. For the strict regulation where the installation of renewables must be at the location of demand, the location specific capacity factors of the renewables are considered.

In more relaxed cases, that allow for investments in the same bidding zone or even in another bidding zone, the capacity factors of renewable energies at the corresponding market levels are taken into account. The temporal correlation is considered through the representation of a "virtual storage"[5]. For the strict case, where the renewable generation and its sourcing must be balanced at the same time, there is no need for a virtual storage. However, once the temporal correlation is relaxed (e.g., balancing over the same day, week, month, year), the storage sums all sourced electricity as well as all produced renewable electricity, that is dedicated for the hydrogen production, within the considered timeframe and ensures that both sums are equal. This temporal decoupling of the electricity generation and the corresponding sourcing enables the hydrogen producer to react to price signals on the power market and to provide flexibility. In times when generation is scarce in the wholesale market, the hydrogen producer can sell its renewable electricity to benefit from high electricity prices. On the contrary, in times when there is surplus electricity in the system, it can then purchase electricity from the market to benefit from low wholesale prices. Consequently, the more the temporal correlation is relaxed, the more flexibility the hydrogen producer can offer to the system and the more it can benefit from trade possibilities. Furthermore, in this regard it might also be beneficial to oversize the renewable capacity to profit from additional revenue streams through the selling of surplus electricity to the market. Therefore, in all cases where electrolysers and renewable generators are grid connected, the model can inject potential renewable surplus electricity to the system.

In the third and last step of the analysis, the outcomes of all modelled regulations are compared based on various parameters. The effect of the regulations on the hydrogen production cost, the CO_2 emissions and the overall welfare are of particular interest.

4. Scenario setup and data

In this study we analyse the case of Germany in 2030. The year 2030 represents the ramp-up phase of a low-carbon hydrogen economy in the country. Germany is a case in point for several reasons. The government did not only decide to phase-out lignite and hard coal-fired power plants by 2038, which have been the backbone for the country's economic growth in the past century, but also to shut down all nuclear power plants by 2022, that have contributed significantly to the power mix in the past decades. Both decisions will change the setup of the power generation substantially in the coming decade. Moreover, the heavy dependence on Russian energy, in particular imports of natural gas, which represented recently still more than 50% of the national natural gas supply, puts Germany under pressure. An immediate import stop as response to Russia's invasion of Ukraine cannot be managed easily as massive volumes would need to be replace rapidly to avoid significant harm to the German society and its economy, that is heavily relying on the production of energy-intensive goods (e.g., steel, chemicals, automobiles). For now, the country's strategy to achieve its decarbonisation goals, carbon neutrality by 2045[6], focused mainly on the massive expansion of renewable energies. With the announcement of the national hydrogen strategy in 2020, low-carbon hydrogen has been set as another pillar. After a technology-neutral start-up phase, the national hydrogen strategy envisages giving priority to the production and use of electrolytic (green) hydrogen in the longer term. Natural gas was considered as transitional fuel and main flexibility provider during the transition phase in the coming years. However, the envisaged role of natural gas in the German energy system is now more uncertain due to the recent geopolitical changes and the new ambition to stop all energy imports from Russia rapidly. Consequently, it is likely that the production of electrolytic hydrogen gains significantly in importance earlier than expected to take over and to substitute some of the natural gas demanding uses.

5 (Schlund and Theile 2021)
6 (German Government 2019)

4.1 Analysed regulatory designs

Although there are many possible regulatory options, as described in Section 2, only a selection of them is analysed and discussed in this study. The final choice is based on the outcome of a variety of trials during the research work of this study. It considers both extreme points (100% off-grid and 100% on-grid) as well as various intermediate options that cover different levels of relaxations on the three dimensions. Table 1 shows the list of options that have been assessed and that are also discussed in the modelling results (Section 5).

Table 1. Overview about analysed regulations

ID	Name	Dimensions			Description
		Temporal	Spatial	Origin	
I	Extreme 1 - 100% off-grid	Same hour	Same location	Additional new RES	Strict requirements on all dimensions. The hydrogen production must take place isolated from the power system with new additional RES
II	100% off-grid + selling	Same hour	Same location	Additional new RES	Similar to the above regulation. However, a grid connection exists to sell surplus electricity to the market instead of curtailing it.
III	Same bidding zone	Same hour	Same bidding zone	Additional new RES	Strict requirements on the temporal dimension (hourly balancing) and on the origin (new additional RES). RES can be installed anyway in the same bidding zone. The transmission grid is used to transfer the renewable electricity between the generation and the demand location.
IV	Other bidding zone	Same hour	All bidding zones	Additional new RES	Strict requirements on the temporal dimension (hourly balancing) and on the origin (new additional RES). RES can be installed in any bidding zone. The transmission grid is used to transfer the renewable electricity between the generation and the demand location.
V	Same day	Same day	Same bidding zone	Additional new RES	Strict requirements on the origin (new additional RES). RES can be installed somewhere in the same bidding zone. The renewable generation and the sourcing must be balanced at a daily level. The transmission grid is used to transfer the renewable electricity between the generation and the demand location.
VI	Same week	Same week	Same bidding zone	Additional new RES	Strict requirements on the origin (new additional RES). RES can be installed somewhere in the same bidding zone. The renewable generation and the sourcing must be balanced at a weekly level. The transmission grid is used to transfer the renewable electricity between the generation and the demand location.
VII	Same month	Same month	Same bidding zone	Additional new RES	Strict requirements on the origin (new additional RES). RES can be installed somewhere in the same bidding zone. The renewable generation and the sourcing must be balanced at a monthly level. The transmission grid is used to transfer the renewable electricity between the generation and the demand location.
VIII	Same year	Same year	Same bidding zone	Additional new RES	Strict requirements on the origin (new additional RES). RES can be installed somewhere in the same bidding zone. The renewable generation and the sourcing must be balanced at a yearly level. The transmission grid is used to transfer the renewable electricity between the generation and the demand location.
IX	Extreme 2 - 100% on-grid	No	No	No	Loose requirements on all dimensions. Electricity can be freely sourced at the market without restriction on any of the dimensions.

4.2 Representation of the power sector

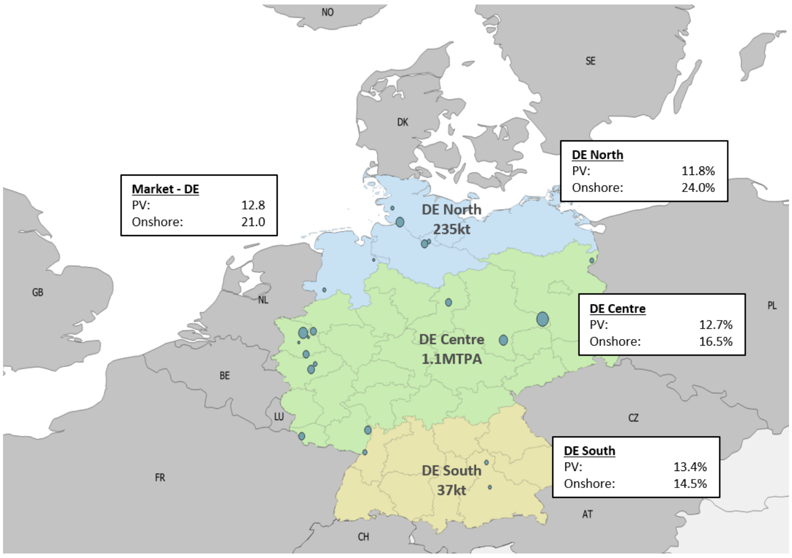
Within the electricity market model, we consider the wholesale market of Germany. Moreover, as an adequate integration of the individual European electricity markets is one of the top priorities of the EU[7] to benefit from exchanges and trade, the interaction of the German system with its interconnected neighbours becomes more important. Therefore, we also include all electricity markets that are directly interconnected to the German market and model them endogenously[8]. Today's generation fleet builds the basis for the capacity expansion in step 1 of our analysis. Data on existing generators were obtained from various sources (Egerer 2016; German Environment Agency 2020; German Federal Network Agency 2020a; Weibezahn et al. 2017). The data are harmonised and corrected by already announced commissioning and decommissioning plans of generators. Furthermore, announced national policy objects in terms of power system evolution such as renewable capacity expansion targets and phase-out policies were taken from the national energy and climate plans[9]. See Table 3 for all considered capacity floors, targets, and caps. Moreover, both the technical parameters of the generating units and their capital expenditures as well as their operational expenditures can also be found in the appendix (Table 4 – Table 7)[10]. The electricity markets are modelled in an hourly resolution for the entire year 2030. All data with hourly resolution[11] are based on the reference year 2019. Corresponding hourly profiles were extracted from timeseries provided by ENTSO-E transparency[12]. The same holds for the weekly water inflows considered for dams. Timeseries that underlie changes in their magnitude until 2030, such as the electricity demand profile and the available net-transfer capacities between the individual markets, are scaled according to annual projections provided by ENTSO-E[9]. All considered commodity prices as well as the price for carbon emission allowances are given in Table 8.

4.3 Representation of the hydrogen supply

Today, hydrogen is mainly used as feedstock in the industry. While additional demand of other sectors is expected to increase in the coming decades, the replacement of these existing fossil-based feedstocks is likely to be among the first uses of hydrogen in the ramp-up phase of a low-carbon hydrogen economy. Therefore, within this study we focus on the captive production and supply of electrolytic hydrogen to the German industry.[13] Derived hydrogen demand figures for 2030 were taken from vom Scheidt et al. (2022). They include the hydrogen demand of four industrial sectors: the production of methanol, ammonia, and steel as well as its use in refineries. The data are geographically resolved which enables to study regulations that target strict requirements on the spatial dimension (e.g., lower than the national level). This is in particular relevant for the extreme case 1, the off-grid case, where the renewable generation has to be near the hydrogen production and demand location. However, instead of modelling all of the 23 industrial hydrogen demand locations listed in (vom Scheidt et al. 2022) individually, we split the country in three parts (north, south and centre) and aggregate the corresponding demand per zone. This approach enables to capture regional renewable resource availabilities while reducing computational complexity. Figure 4 illustrates the considered geographical setup including the hydrogen demand locations, as well as an indication of the three considered geographical levels namely the same location (represented by the three intra-national zones), the same bidding zone and all bidding zones. The annual hydrogen demand values are distributed evenly over all days of the modelled year. Further details on the demand data can be found in the Table 10.

7 EU Energy Union - https://energy.ec.europa.eu/topics/energy-strategy/energy-union_de, Accessed 28.03.2022
8 LU, FR, NL, BE, DK, PL, CZ, AT, CH, UK, NO, SE; Countries with more than one market zone such as DK are only considered by an aggregated market
9 Extracted from (Entsoe 2020) - National Trend Scenario
10 Known values of existing generation units with were prioritized. Only gaps in the data were completed by the values found in the tables.
11 E.g., inelastic electricity demand profiles, renewable capacity factors, net transfer capacities between the bidding zones
12 (Entsoe 2021)
13 In our analysis we only consider the supply of gaseous hydrogen

Figure 4. Considered geographical setup



As described in Section 3, the model can invest endogenously in various system components at the hydrogen demand location. They offer the possibility to better balance the sourced electricity and the hydrogen supply and hence, to reduce the hydrogen production costs. These elements include the storage of electricity in batteries, the conversion of electricity to hydrogen via the two commercially available electrolyser systems (polymer electrolyte membrane electrolyser and alkaline electrolyser) as well as the storage of hydrogen in three different storage technologies. As hydrogen has a low volumetric density under normal conditions compared to other chemical energy carriers (e.g., 3000 times lower than gasoline)[14], it needs to be processed to increase its volumetric density and to offer viable storage possibilities. According to the literature[15], storing hydrogen locally at demand sites can be achieved through three different storage types: in compressed form (GH_2), as hydrogen in liquefied form (LH_2) or as hydrogen that is compound to a carrier material, which is then also referred to as liquid organic hydrogen carriers (LOHC). LOHC are similar in their characteristics to liquid fuels such as gasoline. Typically, GH_2 is stored at pressure levels around 250-300 bar[15]. As the produced hydrogen at the electrolyser outlet has a pressure level between 1-80 bar[16], a compression step is needed to inject it into the storage system. Apart of additional investments in compressor facilities, the compression step also requires additional energy in the form of electricity. When the hydrogen gets released from the storage, the depressurisation does neither required notable additional investments nor further process energy. It is slightly different for the storage of hydrogen as LH_2. The liquefaction process at the storage inlet requires investments in additional system components (liquefaction unit) and significant process energy mainly needed to cool the hydrogen down to -252.76 Degree Celsius[16]. The reconversion to gaseous hydrogen at the outlet of the LH_2 storage requires evaporation units. However, the investment costs for such units are rather small and notable additional process energy is not needed. Storing hydrogen in the form of LOHC requires a hydrogenation unit at the inlet side of the storage, which compounds the hydrogen in an exothermal process to the carrier material. At the storage outlet a dehydrogenation unit is needed to decompose the chemical bound between the hydrogen and its carrier material again. The dehydrogenation process is endothermal and hence, requires process energy in the form of heat. However, as this study analyses the captive supply of gaseous hydrogen to industrial facilities, we assume that there is sufficient excess heat available for the reconversion from LOHC to gaseous hydrogen, so that there is no additional energy demand for the provision of the required process heat. Different potential carrier materials are available and discussed in the literature. Within this study we considered dibenzyl-toluene which seems suitable for this type of application according to (Stöckl et al. 2021). All used data on the individual system components as well as information on their references can be found in Table 11 to Table 13.

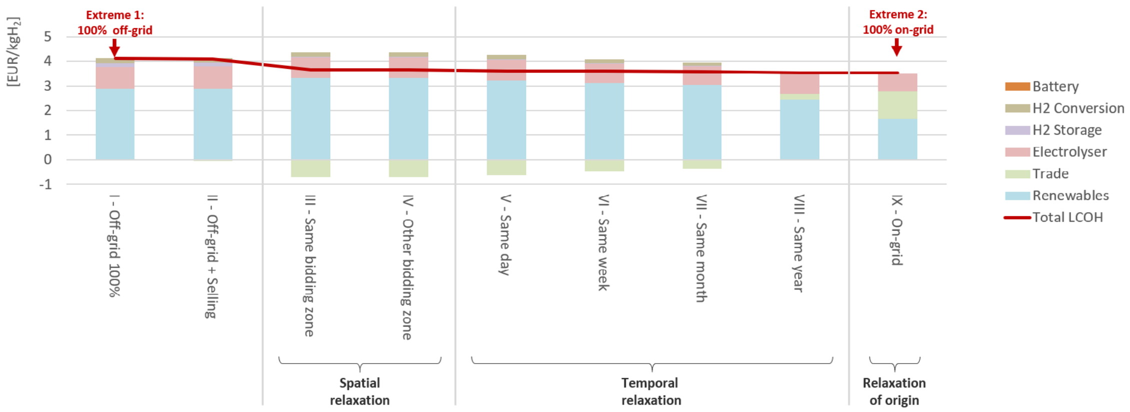
14 Derived from (IEA 2020) and (Salmon and Bañares-Alcántara 2021)
15 (Stöckl, Schill, and Zerrahn 2021)
16 (IEA 2020)

5. Results

5.1 Effect on the hydrogen production costs

The hydrogen production costs are expressed as levelised costs of hydrogen - LCOH. This measure calculates the hydrogen production costs by including all expenses and all potential revenues that occur during the production of hydrogen. Further information on the calculation method can be found in Appendix A.2. Figure 5 illustrates the results of the analysed regulations. Each bar corresponds to one regulation and is composed of several cost elements.

Figure 5. Effect of regulations on hydrogen production costs



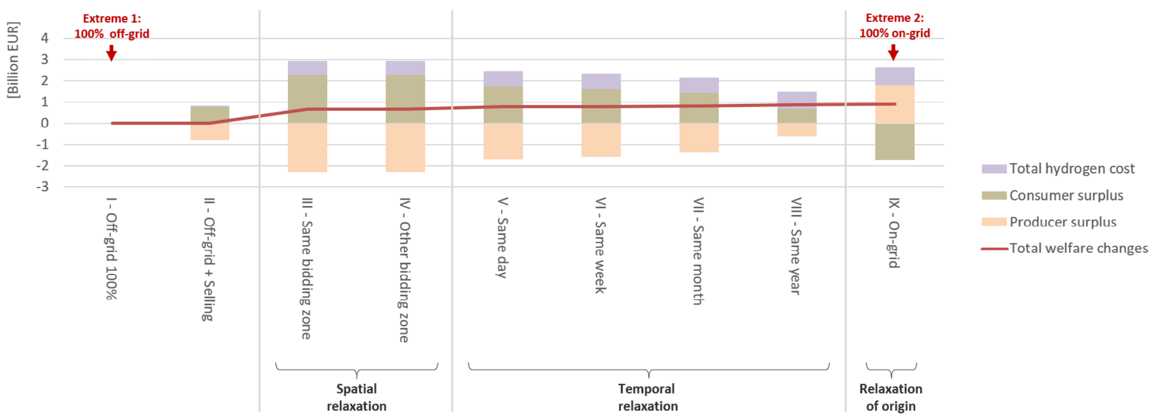
Both, the far-left and the far-right bar represent the two extreme cases. The graphic shows that, the strictest regulation, the 100% off-grid case (I), results in the highest LCOH. The hydrogen production costs are in this case at 4.1 EUR/kgH_2. Moving further right increases the level of relaxations on the different dimensions. In the most relaxed case, the 100% on-grid case (IX), the hydrogen production costs are at 3.5 EUR/kgH_2. Consequently, different levels of regulatory relaxations can reduce hydrogen costs by about 14% (0.6 EUR/kgH2). The biggest drop in LCOH occurs through a relaxation on the spatial dimension. Allowing for installations of renewable energies in the same bidding zone instead of restricting them to the hydrogen demand location (III) reduces costs by about 11% (0.5 EUR/kgH_2). However, further relaxations on the spatial dimension that would also allow for renewable installations in another bidding zone (IV) do not lead to additional reductions in the LCOH. All additional renewable energies would entirely be added to the German bidding zone as in (III). Moreover, relaxations on the temporal dimension reduce the LCOH only to a minor degree. Between the strictest (hourly balance - III) and the loosest case (annual balance - VIII) the costs decrease only by 4%. Furthermore, the graphic shows that depending on the level of relaxation, the composition of the LCOH differs. However, it becomes obvious that in all cases the sourcing of electricity expressed through the costs for additional renewable installations (Renewables) as well as through the trade with the power system (Trade) represents the main contributor to the overall costs. Its share varies between 69-79%. The cost component of the electrolyser system remains rather stable between 0.7 EUR/kgH_2 and 0.9 EUR/kgH_2 accounting for about 20%-24% of all costs. Consequently, the resulting installed electrolyser capacity is relatively independent of the regulation. It varies among the regulations between 14.9 GW and 18 GW. Moreover, one can see that the interactions with the power sector through the selling and the purchasing of electricity (Trade) can either be positive or negative.

While for stricter cases the revenues outweigh the expense and hence, reduce the LCOH, in looser settings the expenses through trade possibilities are bigger than the revenues and add accordingly to the overall production costs. However, in those cases the investments of renewable energies are reduced. The chart also shows that while the model did not invest in battery storage in any of the analysed regulations, hydrogen storage does play a role. However, its contribution to the overall costs remains rather small (0.04 - 0.30 EUR/kgH_2). Nevertheless, investments in hydrogen storage facilities occur in all cases even in the most relaxed one (IX), which highlights their importance. Moreover, the results demonstrate that there is a clear favorite in terms of hydrogen storage technology among the three options. All investments are in LOHC storage facilities and their corresponding conversion and reconversion units.

5.2 Effect on social welfare

Figure 6 shows the change in welfare through the analysed regulations. The individual relaxations are expressed as changes compared to the 100% off-grid case (I), which serves as reference case within this comparison. Each bar is composed of up to three elements namely the differences in consumer and producer surplus in the electricity sector as well as the differences in total hydrogen production costs. Consequently, within this study the term 'welfare' is defined by the sum of the three elements. Further information about their calculation can be found in Appendix A.3.

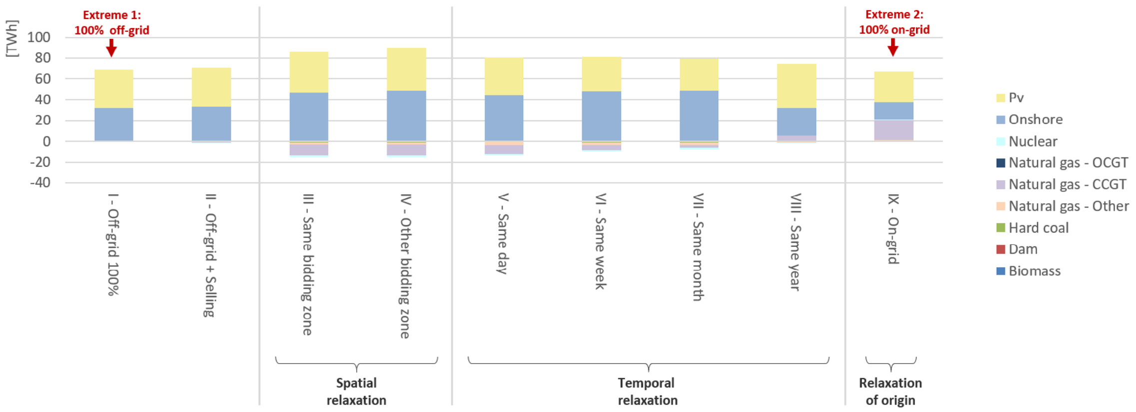
Figure 6. Effect of regulation on total welfare



One sees that welfare increases with increasing levels of relaxations on the three dimensions. At a maximum about 0.9 Billion EUR in additional welfare can be achieved. Similar to the observations in LCOH, the biggest change occurs through a relaxation on the spatial dimension. Allowing for installations of additional renewable energies in the same bidding zone instead of at the demand location, already increases welfare by 0.66 Billion EUR. Moreover, the chart illustrates that the changes in consumer and producer surplus are always opposed. In each of the analysed regulations they have approximately the same magnitude. Consequently, they mostly cancel each other. Therefore, changes in total welfare result to about 95% through changes in overall hydrogen supply costs. Furthermore, one sees that consumers in the electricity sector benefit from a restricted hydrogen production (II-VIII). Only in the unrestricted case, 100% on-grid case (IX), it is the other way round, so that the producers profit more from the provision of hydrogen than the consumers. This can be explained through the change in overall electricity generation as illustrated in Figure 7. The individual bars show the differences between the analysed cases with hydrogen supply to the case where there is no production of electrolytic hydrogen. We see that in the 100% off-grid case (I) there are only additional electricity generation of solar PV and onshore wind. This additional electricity is used entirely at the demand location to produce electrolytic hydrogen. Hence, all excess electricity is curtailed. In all restricted cases, where there is a grid connection (II-VIII) and hence, the possibility to exchange electricity with the power system, the level of additional renewable generation increases.

The injection of this renewable electricity into the grid at marginal costs close to zero replaces some fossil generation at higher marginal costs. This replacement lowers wholesale market prices which results in benefits for the consumers. Only in the unrestricted case (IX), the additional renewable electricity is not sufficient to reduce wholesale market prices. In this case there is even additional fossil generation, which increases overall electricity prices. Consequently, producers in the electricity market benefit more, resulting in a change of signs with the consumers. Moreover, the figure shows that the overall generation of conventional generation units either increases or decreases depending on the regulation. Their generation varies between -15 TWh and +22 TWh. While the generation of some conventional generators is not impacted at all, natural gas-fired power plants are affected the most by the regulations.

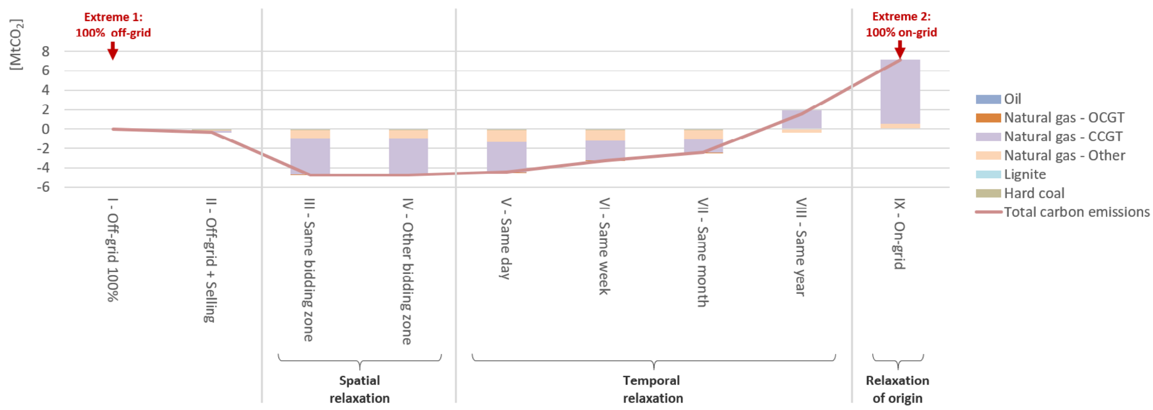
Figure 7. Effect of regulation on electricity generation



5.3 Effect on carbon emissions

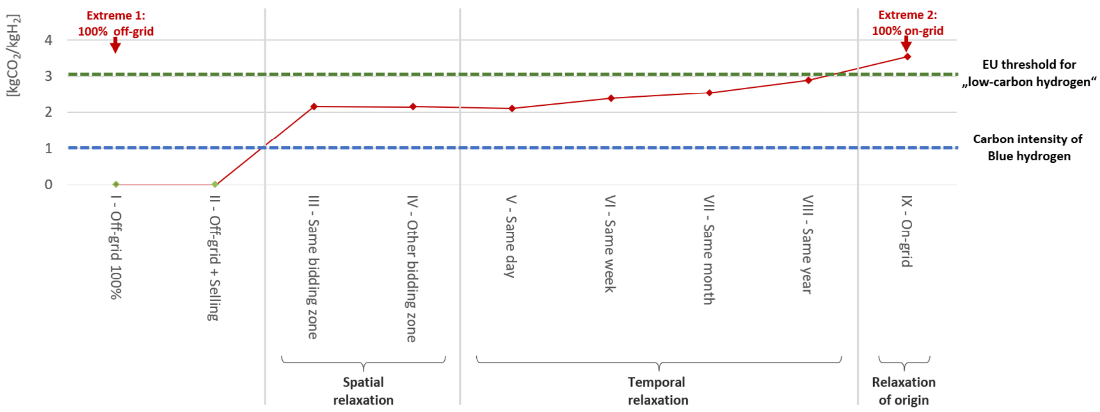
Figure 8 shows the changes in carbon emissions at the system level for the analysed regulatory cases compared to the case where there is no electrolytic hydrogen supply. In the 100% off-grid case (I), there are no changes in carbon emissions at system level as the hydrogen production takes place completely separated from the overall power system. However, in all cases where the hydrogen production interacts with the wider power system (II-IX) overall carbon emissions change. These changes are aligned with the changes in electricity generation (Figure 7). In the most restricted cases, additional renewable electricity replaces some fossil generation and hence, avoids carbon emissions. In the cases, where the spatial correlation is relaxed and the temporal correlation is strict (III-IV), carbon emission savings are maximised and reach savings of about 4.7 $MtCO_2$ per year. The more the temporal correlation is relaxed (V-VII), the less fossil generation is replaced and hence, the less carbon emissions are avoided. In the case, where the generation of renewable electricity and its sourcing can be balanced over a year (VIII), carbon emissions at the system level increase to about 1.6 $MtCO_2$. In the unrestricted case, the 100% on-grid (IX), significant amounts of additional fossil electricity are generated, so that carbon emissions grow to about 7.2 $MtCO_2$. The impacts on the changes in carbon emissions result from and are aligned with the changes in the operation of the conventional power generators as described in the subsection above. Consequently, natural gas-fired power plants are the main contributors to changes in carbon emissions.

Figure 8. Effect of regulation on carbon emission at the system level



Beside the effect of different regulations on carbon emissions at the system level, the regulations also affect the carbon content of the produced hydrogen as shown in Figure 9. While in the off-grid settings (I-II) all sourced electricity comes directly from the renewable facility so that the produced hydrogen has a carbon intensity of zero, in all cases where electricity is transported through and sourced from the grid (III-VIII) the carbon content of hydrogen increases. It varies between 2 and 3 $kgCO_2/kgH_2$ except for the unrestricted case (IX), where it reaches 3.5 $kgCO_2/kgH_2$. Consequently, as illustrated in the figure, for most analysed cases the carbon intensity is above the one of blue hydrogen. However, the EU threshold for low-carbon hydrogen[17] of 3 $kgCO_2/kgH_2$ is not reached in the regulated cases (I-VIII). Only in the unrestricted case the threshold is surpassed.

Figure 9. Effect of regulations on the carbon intensity of the produced hydrogen



Combining the information on the carbon intensity of the produced hydrogen and the one on the carbon emissions at the system level provides additional insights. It shows that although the carbon intensity of the electrolytic hydrogen produced is mostly higher than that of the blue hydrogen, the production of electrolytic hydrogen has a positive impact on carbon emissions in the power sector, as CO_2 emissions overall decrease. This external effect is not present in the production of blue hydrogen, as the process is independent of the power sector. Furthermore, the combined information also demonstrate that the EU threshold of 3 $kgCO_2/kgH_2$ does not necessarily result in carbon emission reductions at the system level. This is also illustrated by the case where the renewable electricity generation and its sourcing is balanced over one year (VIII). While the carbon intensity of the produced electrolytic hydrogen is at 2.9 $kgCO_2/kgH_2$ and hence, slightly below the threshold, overall carbon emissions in the power sector increase by 1.6 $MtCO_2$.

17 (European Commission 2021a) 70% greenhouse gas emission reduction compared to fossil fuels - Benchmark 10 kgCO2/kgH2 for hydrogen produced in the conventional SMR processes without CCS.

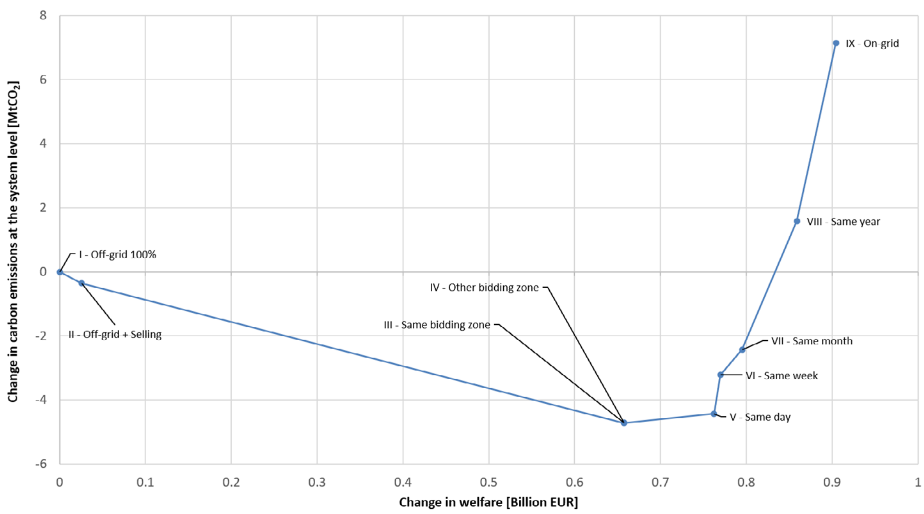
5.4 Trade-off between environmental integrity and economic viability

Figure 10 summarises the outcomes of the above analysis through the Pareto front between changes in welfare and the resulting changes in carbon emissions at the system level. In the figure, all analysed regulations are expressed as the difference to the 100% off-grid case (I). One can see that strict regulations (both off-grid cases – I&II) do neither lead to ideal outcomes in terms of CO_2 emission reductions nor in terms of welfare optimisation. All other analysed regulations illustrate the trade-off between environmental integrity and economic viability as they lie on the Pareto front. While stricter regulations on the temporal correlation result in minimised carbon emissions (III-VI), easing them (VII-VIII) or even allowing for an unrestricted production of electrolytic hydrogen (IX) increases carbon emissions but rises welfare. Moreover, both the regulation that allows for the balancing at an annual level (VIII) as well as the unrestricted case (IX), result overall in increased carbon emission levels compared to a system configuration without the production of electrolytic hydrogen.

5.5 Sensitivity analysis

To check the robustness of the results, a sensitivity analysis is carried out. It includes the variation of the CO_2 price, the natural gas price as well as the capital expenditures of renewable energy plants and hydrogen technologies.

Figure 10. Pareto frontier between changes in welfare and changes in carbon emissions



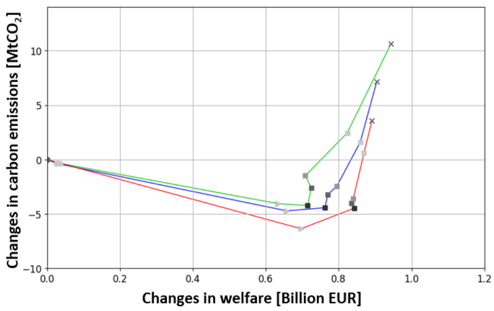
Within the sensitivity analysis the four parameters are varied by +10% and -10% and compared to the reference settings. Increasing CO_2 prices (Figure 11a) lead to a convergence of the results. This applies in particular to relaxations on the temporal correlation. The results of the regulations with a balancing period over a day, week and month (V-VII) are very close in terms of changes in welfare and in carbon emissions. Furthermore, the changes in welfare between the unrestricted case (IX) and the case where the temporal balancing is allowed at a daily level (V) shrink substantially. Moreover, one sees that due to an overall greener electricity system, the hydrogen production results in much lower additional carbon emissions. The observed effects are reversed for lower CO_2 prices. Changes in natural gas prices (Figure 11b) show approximately the same effects as the ones in CO_2 prices. This outcome confirms that the analysed power system in 2030 is mainly dominated by the electricity generation from natural gas-fired power plants. Consequently, higher natural gas prices cause the same effect as higher CO_2 prices and the other way around. However, more optimistic cost declines in renewable energies (Figure 11c) also lead to a convergence of the results of the analysed regulations. Especially the changes in welfare shrink significantly. The results of the case where the balancing is allowed over a day (V) and the unrestricted case (IX) as well as all intermediate regulations are almost on a vertical line.

There are hardly differences in welfare. Only changes in carbon emissions remain for these cases which show an overall declining trend. Even in the unrestricted case (IX) only about 2.5 Mt of additional carbon emissions result. Less optimistic declines in renewable costs cause opposite effects. Changes in the costs of the hydrogen technologies (Figure 11d) including the costs of electrolysers and the costs of hydrogen conversion and storage units, do not have a major impact on the results. The curves of both the upper and the lower sensitivity are slightly offset compared to the reference data. This shows that the hydrogen technology costs have only a minor impact on the overall system and its operation. This confirms again that the main driver for the competitiveness of electrolytic hydrogen is the provision of low-cost electricity rather than cost declines in hydrogen technologies.

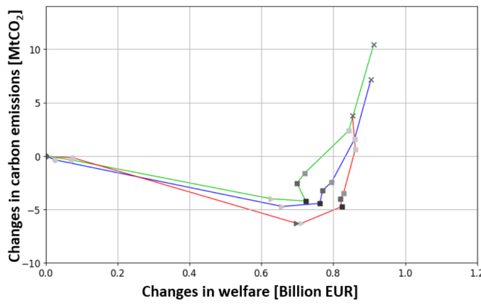
6. Discussion

Our analysis shows that the implementation of potential regulations for the production of electrolytic hydrogen have different effects on the hydrogen supply costs, on total welfare and on carbon emissions. Our findings confirm the presence of the trade-off between environmental integrity and economic viability. We find that stricter regulations generally lead to beneficial environmental effects, while looser ones improve hydrogen supply costs and total welfare. However, too strict regulations on the geographical correlation that require renewable electricity to be generated near the electrolyser systems result neither in optimal outcomes in terms of carbon emissions nor in terms of welfare gains.

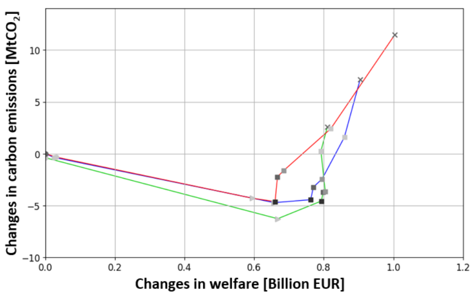
Figure 11. Sensitivity analysis



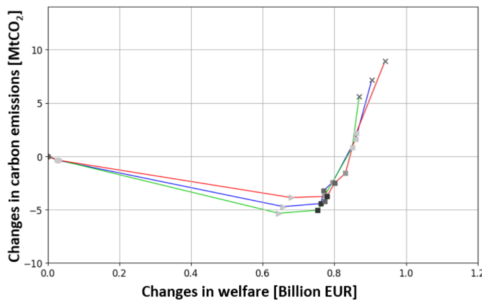
(a) CO2 price



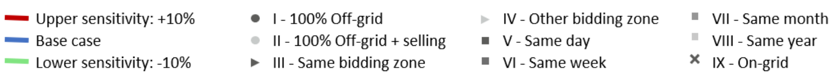
(b) Natural gas price



(c) Capex of renewable energies



(d) Capex of hydrogen technologies



The costs for the hydrogen supply are by about 15% higher in these cases compared to other analysed regulations. The main reason for this is the comparable low resource availability of renewable energies in the centre of the country where most of the hydrogen demanding industry is located. However, once regulations allow for the spatial decoupling of renewable facilities and the electrolyser systems, so that renewables can be installed at more favourable sites anywhere in country, hydrogen supply costs do not change much anymore (~ -4%). Consequently, as reductions in hydrogen supply costs are responsible for about 95% of the total welfare changes, the allowance for renewable installations anywhere in the bidding zone, also causes the biggest gain in total welfare. Moreover, the results show that a further relaxation of the geographical correlation, that even allows for installations of renewable energies in other bidding zones, do not lead to additional benefits neither environmentally nor economically. The transfer capacities between the individual bidding zones are already exhausted through the operation of the power system without any production of electrolytic hydrogen in Germany. Consequently, the electrolytic hydrogen production in Germany cannot benefit from higher resource availabilities of renewables in other countries to reduce costs.

Overall, our findings are aligned with the ones of Schlund and Theile (2021) and confirm their outcomes. However, in addition to their study that focused only on the dimension of the temporal correlation we enlarged the analysis through the consideration of two additional dimensions that are part of the ongoing regulatory discussions namely the geographical correlation and the origin of the electricity. In a direct comparison to Schlund and Theile (2021) our findings show that the regulatory effect of longer balancing periods are less distinct. One main reason for the difference is the considered time horizon. While Schlund and Theile (2021) analyse the effect of regulations on the current power system, our analysis focuses on the year 2030, when the power system in central Europe is likely to have changed significantly due to the evolved reduction in fossil generation, the phase-out of nuclear power in various countries and the massive expansion of renewable energies. Another major difference between the studies is that we also consider the installation of solar PV plants as well as offshore wind farms and do not limit the renewable electricity provision only to onshore wind turbines. Consequently, due to the considered technology mix, seasonal differences in resource availabilities between the individual technologies can be balanced better, which affects the hydrogen production costs positively. To avoid overestimating the effects of regulations, it is therefore suggested that further analyses should neither be restricted to historical settings nor limited to a reduced set of renewable technologies.

The consideration of hydrogen storage also plays an important role and drives the results of our analysis. The possibility of decoupling the production and supply of hydrogen over time means that periods of low availabilities of renewable energies can be bridged with periods of relatively high resource availabilities. The storage of hydrogen in the form of LOHC is identified as the most economical storage option within the setting of this case study. Even in the unrestricted case, LOHC storage capacity is installed, which proves the viability of the technology. The storage systems enable to benefit from the sourcing of electricity during hours when the share of renewables in the system is high and the prices are low. Potential curtailments of renewable excess electricity can be avoided, leading to a better system integration of renewable energies. This confirms the findings of Ruhnau (2020), who states that the flexible production of electrolytic hydrogen helps to integrate renewable energies in the system and stabilises their market value. However, we focus entirely on the supply of electrolytic hydrogen to the industry and assume that sufficient excess heat for the dehydrogenation process is available at the industrial sites. Once this heat provision causes additional energy needs to the system, LOHC as storage technology might become less competitive compared to other technologies as shown by (Stöckl et al. 2021). Consequently, for other end-uses, where no excess heat is available, the role of storage technologies and their positive effect on the system could therefore decrease.

Moreover, our results show that independently of any requirements for the sourcing of electricity, the production of electrolytic hydrogen results in significant additional renewable energy capacity. Even in the unrestricted case, the most pessimistic case in terms of additional renewable energy capacity, additional 37 GW are installed. In this case the generated renewable electricity of these facilities contributes to 35% to the energy content of the produced hydrogen, which is already a non-negligible share. This shows that the combination of renewable electricity and hydrogen storage to produce electrolytic hydrogen is already economically viable to some extent in the near future. With further decreasing capital expenditures of renewable energies, it is likely that the economics of this combination further improves. Consequently, the trade-off between environmental integrity and economic viability is likely to vanish with the evolution of the power sector as both the optimal economic options and the optimal environmental options converge. Therefore, corresponding regulations should already be superfluous in the medium term. This is also shown in our sensitivity check. A reduction in renewable energy costs of only -10% already reduces additional carbon emissions by two-thirds in the unconstrained case. The combined evolution of key parameters such as the decline in renewable costs, a drop in hydrogen technology costs and increasing CO_2 prices, which can all be expected, have a concurrent effect of moving the production of electrolytic hydrogen fed by renewable electricity towards the most economical position. Rising natural gas prices show similar effects. Consequently, given the current situation and the resulting uncertainties in the availability of sufficient natural gas volumes and the related price effects might further foster the profitability of renewable electricity in the production of electrolytic hydrogen.

The EU's ambition to impose sanctions to Russia and to stop all energy imports requires to find alternative energy supply options shortly. In the case of natural gas, this is particularly difficult due to the massive dependency on Russia and the necessary infrastructure requirements for imports from other regions that are partly linked to long lead times. Therefore, any reduction in natural gas demand would help to reduce import dependencies on Russia sooner. Regulations for the production of electrolytic hydrogen can contribute to this. Under the underlying assumptions of our analysis, the power sector in central Europe is mainly dominated by renewable energies and natural gas-fired power plants that provide most of the required flexibility. Stricter requirements for the production of electrolytic hydrogen lead to substantial renewable electricity that is in excess to the demanded electricity for the hydrogen production. Consequently, hydrogen producers would inject it to the power system to obtain additional revenues from selling it. This injected surplus electricity replaces some of the fossil generation which is mainly electricity generated by natural gas-fired power plants. In the analysed regulatory cases, natural gas demand can be reduced by up to 23 TWh. However, the looser the regulations, the lower the reduction potential. For very loose constraints, natural gas demand even increases.

Moreover, in context of the Russian invasion and the energy crisis, policy makers aim at reducing the burden of high energy costs on consumers. Different possibilities such as price caps are currently being discussed. Our results highlight that the production of electrolytic hydrogen and corresponding regulations have different effects on the electricity consumers. The outcomes show that strict regulations favour the situation for consumers as more renewable electricity is added to the system that results in reduced electricity wholesale market prices. Except for the very strict regulation, the off-grid cases, one can say that the stricter the regulation, the more surplus electricity is added to the system and the more the consumers benefit from reduced electricity prices. For the unrestricted case the situation changes. The additional electricity mostly generated by natural gas-fired power plants increases wholesale prices and hence, favours electricity producers rather than consumers.

Furthermore, while onshore wind and solar PV plants are rather balanced in their contribution to the provision of renewable electricity to the electrolyser systems throughout the analysed regulations within the study, offshore wind does not play a role. However, current trends show that major electrolyser projects are planned to be fed by offshore wind farms in the North Sea[18].

18 For instance: Aquaventus (https://www.aquaventus.org/) and North2 (https://www.north2.eu/)

Given that on the one hand the costs for the electricity sourcing present the major cost component in the production of electrolytic hydrogen and on the other hand that the levelised costs of electricity from offshore wind farms are still significantly higher than the ones of solar PV and onshore wind[19], raises questions about the electricity sourcing strategy of these projects and their competitiveness.

7. Conclusion

Hydrogen is expected to be a key element in achieving the EU's climate ambitions alongside the concept of direct electrification through renewable energies. However, the production of electrolytic hydrogen comes with a dilemma: while renewable electricity with no direct carbon emissions results in higher hydrogen supply costs, using grid electricity lowers costs. Consequently, there is a trade-off between environmental integrity and economic viability. Prioritising environmental aspects could hinder the timely development and the ramp-up of a hydrogen economy, while favoring economic aspects could counteract the decarbonisation process. Therefore, the recognition of electrolytic hydrogen as a homogeneous good does not seem appropriate, which requires the introduction of clear definitions and regulations. Policymakers are about to frame the conditions for the production of electrolytic hydrogen. These need to be well conceived to contribute to the wider goals and to provide a sound basis for an informed decision making by private investors.

In this study, we analyse the effect of various possible regulations on hydrogen supply costs, total welfare and on carbon emissions for the case of Germany in 2030. The analysed regulations are based on the three dimensions that frame the ongoing discussions: (1) the origin of the electricity, (2) the geographical correlation of electrolyser systems and renewable energy facilities and (3) the temporal correlation of the generated renewable electricity and the sourced electricity. Different levels of relaxation on the three dimensions are considered and included in the analysis which relies on the deployment of a detailed electricity market model.

We find that strict requirements generally benefit environmental aspects, while loose conditions favour hydrogen production costs and total welfare (not accounting for the environmental costs). However, too strict regulations on the geographical dimension that only allow for the sourcing of renewable electricity generated in proximity do neither result in beneficial economic nor in optimal environmental outcomes. While in the most environmentally friendly regulation 4.7 Mt of carbon emissions can be reduced, the best economic outcome results in 0.9 Billion EUR of welfare gains. The main driver for increasing welfare is identified to be reductions in hydrogen supply costs that vary by about 15% among the analysed regulations.

Moreover, the results show that stricter requirements result in substantial surplus renewable electricity that does not only replace some fossil generation to reduce carbon emissions but that also decreases electricity market prices and hence, favours consumers. Both aspects, the reduction in natural gas demand and the financial relief of consumers, are very relevant in the context of the EU's ambition to sanction Russia through a stop of energy imports – REPowerEU. In looser regulatory cases it is the other way round. Caution should also be paid when setting thresholds for allowed carbon intensities of the sourced electricity. We found that the threshold set by the EU, which requires at least a 70% reduction in greenhouse gas emissions from the production of electrolytic hydrogen compared to fossil options, does not necessarily result in reductions of carbon emissions at the system level.

19 (IRENA 2020)

We conclude that when designing regulation, policymakers must strike a careful balance between environmental and economic aspects to neither harm the decarbonisation process nor the ramp-up of a low-carbon hydrogen economy. Favouring one over the other might result in undesirable effects. However, weighting the various advantages of relatively strict regulations on all regulatory dimensions against the comparatively minor economic disadvantages, suggests that stricter regulations are well-suited to reduce carbon emissions, exonerate consumers financially, further upscale renewable energies to achieve additional learning effects and to reduce natural gas demand helping to diminishing import dependencies.

Moreover, the combination of renewable electricity and hydrogen storage technologies, that showed an important role within the study, arguing for its consideration in future analyses, are already economically viable to a certain degree. As the profitability of this combination improves, it will be both economically and environmentally optimal in the medium term. Consequently, the trade-off between environmental integrity and economic viability will diminish over time and with it the need for regulations for the production of electrolytic hydrogen.

This study focuses on the provision of electrolytic hydrogen for the German industry, as it is considered one of the first sectors to use low-carbon hydrogen on a large scale. Including other end-uses to the analysis such as the transport sector, could provide additional insights, as the hydrogen supply structure is different from the one in the industry. An analysis of other countries can also result in additional findings, as the composition of their generation fleet and their interconnections with neighbouring market zones can be very different. Both aspects offer starting points for further research to gain a better understanding of the effects of regulating electrolytic hydrogen production. Moreover, the focus of the work was set entirely on a market level. Consequently, resulting power flows and potential effects on grid congestions caused by the analysed regulations were not addressed. The same holds for the consideration of a dedicated hydrogen infrastructure. We assumed that neither dedicated pipelines nor large-scale hydrogen storage facilities are available by 2030. Both aspects provide further research directions and extensions of the applied methodology.

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Annex

A1. The electricity market model

Type	Symbol	Description	Unit
Variables			
	p	Endogenous power flow (e.g. power generation)	[MW]
	p^{ch}	Storage charging power	[MW]
	p^{dis}	Storage discharging power	[MW]
	p^{curt}	Curtailed renewable power	[MW]
	p^{src}	Sourced power for electrolytic hydrogen production	[MW]
	p^{pro}	Power generated by newly build RES dedicated for electrolytic hydrogen production	[MW]
	p^{sur}	Power generated by newly build RES dedicated for the selling at the market	[MW]
	p^{inj}	Power injection into electrolyser	[MW]
	q^{cap}	Considered capacity in the power sector	[MW]
	q^{inv}	Invested capacity in the power sector	[MW]
	q^{div}	Divested capacity in the power sector	[MW]
	q^{bat}	Investments in battery storage for hydrogen supply	[MW]
	q^{pth2}	Investments in electrolyser systems for hydrogen supply	[MW]
	q^{sto}	Investments in hydrogen storage for hydrogen supply	[MW]
	q^{con}	Investments in hydrogen conversion facilities for hydrogen supply	[MW]
	q^{res}	Investments in additional RES for hydrogen supply	[MW]
	q^{vol}	Total storage volume of storage facility in the power sector	[MWh]
	l	Storage level	[MWh]
	c^{ass}	Cost: Fixed and investment costs of power generation facilities	[EUR]
	c^{h2}	Cost: Components required for hydrogen supply	[EUR]
	c^{gen}	Cost: Power generation for electricity supply	[EUR]
Parameter (exogenous)			
	C^{mc}	Cost: Marginal cost	[EUR/MWh]
	C^{co2}	Cost: CO_2	[EUR/tCO_2]
	C^{fuel}	Cost: Fuel	[EUR/MWh_{raw}]
	C^{vom}	Cost: Variable operation and maintenance	[EUR/MWh]
	C^{an}	Cost: Annualized captial expenditures	[EUR/MWh]
	Q^{init}	Initial capacity	[MW]
	P^{exp}	Export power flow	[MW]
	P^{imp}	Import power flow	[MW]
	P^{load}	Electrical load	[MW]
	V^{cf}	Capacity factor	[%/100]
	V^{avail}	Capacity factor	[%/100]
	V^{em}	Fuel emissions	[tCO_2/MWh_{raw}]
	V^{inflow}	Water inflow in reservoirs of dams	[MW]
	V^{maxd}	Maximial annual electricity demand	[MW]
	V^{cre}	Capacity credit	[#]
	$V^{anc,con}$	Ancillary electricity demand for conversion units	[#]
	$V^{anc,rec}$	Ancillary electricity demand for conversion units	[#]
	W^{pro}	Producer surplus	[EUR]
	W^{con}	Consumer surplus	[EUR]

	W^{h2}	Total cost for hydrogen supply	[EUR]
	eta	Efficiency	[%/100]
Lower indicies			
	t	Hourly timestep	
	z	Zone of hydrogen demand	
	g	Generation unit	
	s	Storage unit	
	m / mm	Market zone	
	f	Fuel type	
	e	Electrolyser type	
	c	Storage form of hydrogen	
	b	Battery type	
	r	RES type	
	l	Geospatial correlation	
Sets			
	T_{bal}	All hours of regulation specific balancing period (e.g., daily, weekly, monthly)	
	T_{day}	All hours of a day	
	T_{week}	All hours of a week	
	T_1	First hour of the year	
	T_{8760}	Last hour of the year	
	T	Hours of the year	
	M	Electricity markets	
	Z	Zones with hydrogen demand (e.g., DE north, DE south, DE center)	
	S	Storage units	
	G	Generation units	
	R	Renewable generators	
	D	Dams	
	F	Fuel type (e.g. Natural gas, solar PV, nuclear)	
	B	Battery type	
	E	Electrolyser type (e.g., PEM, alkaline)	
	C	Hydrogen storage types (e.g., LH_2, CH_2, LOHC)	
	L	All locations of regulation specific geographical correlation (e.g. Same bidding zone)	

The electricity market model is formulated as linear optimisation problem and represents a stylised form of the wholesale market. It aims at minimising the costs for the supply of exogenous demand.[20] The model results in an hourly plant dispatch of every generating unit within the considered spatial and temporal scope as well as in endogenous investments and divestments in various technologies. The objective function (1) minimises overall system costs. It consists of three parts: the costs of the power generation units (cass - only in step 1), investment costs for the components required to supply the hydrogen (ch2 - only in step 2) and the generation costs for the total electricity supply (cgen).

$$\min c^{ass} + c^{h2} + c^{gen} \tag{1}$$

Each of the individual elements can be described in more details. We first only introduce the parts that are common to both applications of the model namely step 1 and step 2 of the analysis. In subsection 7.1 and 7.2 we then introduce the elements that are specific for each of the two steps.

The total generation costs are the sum of both, the operational costs of all generation units and the cost occurring through the charging and discharging of storage facilities (2).

$$c^{gen} = \sum_{m}^{M} \sum_{g}^{G} \sum_{t}^{T} p_{m,g,t} \cdot c_{m,g}^{mc} + \sum_{m}^{M} \sum_{s}^{S} \sum_{t}^{T} \left(p_{m,s,t}^{ch} + p_{m,s,t}^{dis}\right) \cdot c_{m,s}^{mc} \tag{2}$$

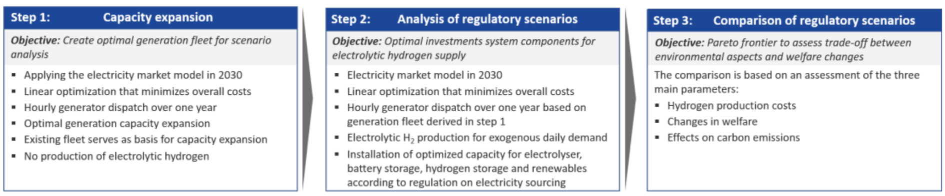
The marginal costs for generation and storage units are calculated by (3) and (4) respectively.

$$c_{m,g}^{mc} = \frac{1}{\eta_{m,g}} \cdot \left(c_f^{fuel} + c^{CO2} \cdot v_f^{em}\right) + c_g^{vom} \qquad \forall g \in f \tag{3}$$

$$c_{m,s}^{mc} = \frac{1}{\eta_{m,s}} \cdot \left(c_f^{fuel} + c^{CO2} \cdot v_f^{em}\right) + c_s^{vom} \qquad \forall s \in f \tag{4}$$

The costs minimisation is subject to various constraints. (5) represents the balance of all power generation and all electrical demand at both every timestep and every market zone.

(5)



The power production of renewables in the electricity market is set by their installed capacity and the corresponding capacity factor as expressed in (6).

$$p_{m,g,t} = q_{m,g}^{cap} \cdot v_{m,g}^{cf} \qquad \forall g \in R, \forall t \in T \tag{6}$$

20 Except for the endogenous demand caused by PtH2 units

(7) and (8) limit the decision variables of the power generation and the power exchange between neighbouring countries to their available capacity.

$$0 \leq p_{m,g,t} \leq q_{m,g}^{cap} \cdot V_{m,g,t}^{avail} \qquad \forall m \in M, \forall g \in C, \forall t \in T \tag{7}$$

$$p_{m,mm,t} \leq V_{m,mm}^{cap} \cdot V_{m,mm,t}^{avail} \qquad \forall m \wedge mm \in M, \forall t \in T \tag{8}$$

Storage units, that include both pumped hydro storage and battery storage facilities are represented by (9) to (12). Where (9) and (11) define the storage level of all storage facilities at the beginning and at the end respectively, and (10) the intermediate storage level within the year. The corresponding decision variables of the storage representation are limited by the given maximum capacities (12).

$$l_{m,s,t} = q_{m,s}^{vol} \cdot 0.5 + p_{m,s,t}^{ch} \cdot \eta_{m,s} - \frac{p_{m,s,t}^{dis}}{\eta_{m,s}} \qquad \forall m \in M, \forall s \in S, \forall t \in T_1 \tag{9}$$

$$l_{m,s,t} = l_{m,s,t-1} + p_{m,s,t}^{ch} \cdot \eta_{m,s} - \frac{p_{m,s,t}^{dis}}{\eta_{m,s}} \qquad \forall m \in M, \forall s \in S, \forall t \in T \tag{10}$$

$$q_{m,s}^{vol} \cdot 0.5 = l_{m,s,t-1} + p_{m,s,t}^{ch} \cdot \eta_{m,s} - \frac{p_{m,s,t}^{dis}}{\eta_{m,s}} \qquad \forall m \in M, \forall s \in S, \forall t \in T_{8760} \tag{11}$$

$$0 \leq l_{m,s,t} \leq q_{m,s}^{vol}, \quad 0 \leq p_{m,s,t}^{dis} \leq q_{m,s}^{cap}, \quad 0 \leq p_{m,s,t}^{ch} \leq q_{m,s}^{cap} \qquad \forall m \in M, \forall s \in S, \forall t \in T \tag{12}$$

Beside the consideration of storage facilities in the model, hydro reservoirs that only allow to produce electricity by releasing water from the reservoirs are also included in the modelling. Often this technology is referred to 'dams'. We constraint the operation of dams through the weekly balance of energy inflows and outflows (13).

$$\sum_{t}^{T_{week}} p_{m,g,t} = \sum_{t}^{T_{week}} V_{m,g,t}^{inflow} \qquad \forall m \in M, \forall g \in D \tag{13}$$

A.1.1. Investment mode

The total investment costs of generation units includes both the annualised capital expenditures of possible investments and the fixed operational expenditures of all installed units (14) to (16).

$$c^{ass} = c^{inv} + c^{fix} \tag{14}$$

$$c^{inv} = \sum_{m}^{M}\sum_{g}^{G} q_{m,g}^{inv} \cdot V_{g}^{an} + \sum_{m}^{M}\sum_{s}^{S} q_{m,s}^{inv} \cdot V_{s}^{an} \tag{15}$$

$$c^{fix} = \sum_{m}^{M}\sum_{g}^{G} q_{m,g}^{cap} \cdot V_{g}^{fix} + \sum_{m}^{M}\sum_{s}^{S} q_{m,s}^{cap} \cdot V_{s}^{fix} \tag{16}$$

The available generation capacity is determined using (17) and (18). The initial starting capacity is set through the existing power plant fleet and is imputed as exogenous data input.

$$q_{m,g}^{cap} = Q_{m,g}^{init} + q_{m,g}^{inv} - q_{m,g}^{div} \qquad \forall m \in M, \forall g \in G \tag{17}$$

$$q_{m,s}^{cap} = Q_{m,s}^{init} + q_{m,s}^{inv} - q_{m,s}^{div} \qquad \forall m \in M, \forall s \in S \tag{18}$$

The generation fleet might fulfil certain capacity levels that are set by the national governments (e.g., expansion targets of renewable energies, capacity reductions due to phase-out policies). To include these aspects three additional constraints are added to the model, that set either a capacity cap (19), a capacity target (20) or a capacity floor (21) for the affected energy types.

$$V_{m,g}^{lim} \geq \sum_{c}^{C} q_{m,g}^{cap} \qquad \forall m \in M, \forall g \in G; \qquad V_{m,s}^{lim} \geq \sum_{c}^{C} q_{m,s}^{cap} \qquad \forall m \in M, \forall s \in S \tag{19}$$

$$V_{m,g}^{flo} \leq \sum_{c}^{C} q_{m,g}^{cap} \qquad \forall m \in M, \forall g \in G; \qquad V_{m,s}^{flo} \leq \sum_{c}^{C} q_{m,s}^{cap} \qquad \forall m \in M, \forall s \in S \tag{20}$$

$$V_{m,g}^{tar} = \sum_{c}^{C} q_{m,g}^{cap} \qquad \forall m \in M, \forall g \in G; \qquad V_{m,s}^{tar} = \sum_{c}^{C} q_{m,s}^{cap} \qquad \forall m \in M, \forall s \in S \tag{21}$$

To ensure capacity adequacy in each of the considered power markets, a constraint on the overall capacity is introduced per market zone (22). It ensures, that the installed capacity is greater than the occurring maximal electricity load[21] that is increased by a security factor of 10%. Parameter V_{cre}, is the so-called capacity credit, that is a pre-defined value accounting for the statistical permanent availability of the individual energy types. Consequently, the value reduces the risk of insufficient available capacity at any given time. Corresponding values for the capacity credit can be found in Table 9.

21 Without consideration of the load increases through the hydrogen demand

$$V_m^{maxd} \cdot 1.1 \leq \sum_c^C \left(g_{m,g}^{cap} \cdot V_g^{cre}\right) + \sum_s^S \left(g_{m,s}^{cap} \cdot V_s^{cre}\right) \qquad \forall m \in M \tag{22}$$

A.1.2. Hydrogen supply

The costs linked to the supply of hydrogen are represented through (23). They include investment costs for battery storage facilities, electrolyser systems, hydrogen storage units as well as the costs for all required conversion steps. Furthermore, the investment expenditures of potential capacity additions of renewable energies are added.

$$c^{h2} = \sum_z^Z \sum_b^B q_{z,b}^{bat} \cdot C_b^{an} + \sum_z^Z \sum_e^E q_{z,e}^{pth2} \cdot C_e^{an} + \sum_z^Z \sum_c^C \left(q_{z,c}^{sto} \cdot C_c^{sto,an} + q_{z,c}^{con} \cdot C_c^{con,an}\right) + \sum_z^Z \sum_r^R q_{z,r}^{res} \cdot C_r^{an} \tag{23}$$

The supply of hydrogen is described by two balancing equations (24) and (25) that are similar to the one for each electricity market zone (5). Equation (24) represents the balancing of volumes on the electrical side of the electrolyser (input) and equation (25) the balancing of volume flows on the hydrogen side (output). They ensure an adequate supply of the exogenous hydrogen demand for every considered location.

$$p_{z,t}^{src} = \sum_b^B \left(p_{z,b,t}^{ch} - p_{z,b,t}^{dis}\right) + \sum_e^E p_{z,e,t}^{inj} + \sum_c^C \left(p_{z,c,t}^{ch} \cdot V^{anc,con} + p_{z,c,t}^{dis} \cdot V^{anc,rec}\right) \qquad \forall z \in Z, \forall t \in T \tag{24}$$

$$\sum_e^E \left(p_{z,e,t}^{inj} \cdot \eta_e\right) = \sum_c^C \left(p_{z,c,t}^{ch} - p_{z,c,t}^{dis}\right) + p_{z,t}^{sup} \qquad \forall z \in Z, \forall t \in T \tag{25}$$

The supply of hydrogen needs to match the exogenous hydrogen demand on a daily level as shown on (26).

$$\sum_t^{T_{day}} p_{z,t}^{sup} = \sum_t^{T_{day}} P_{z,t}^{load,h2} \qquad \forall z \in Z, \forall t \in T \tag{26}$$

The electricity that is injected into the electrolyser is restricted by the installed capacity of the system (27).

$$p_{z,e,t}^{inj} \leq q_{z,e}^{pth2} \qquad \forall z \in Z, \forall e \in E, \forall t \in T \tag{27}$$

While the battery storage on the electrical side of the electrolyser is described similarly as for the storage facilities in the electricity market representation (see (9)-(12)), the hydrogen storage includes additional restrictions through the conversion and reconversion units. Hydrogen storage facilities are described by equations (28) to (31).

$$l_{z,c,t} = q^{sto}_{z,c} \cdot 0.5 + p^{ch}_{z,c,t} \cdot \eta_{z,c} - \frac{p^{dis}_{z,c,t}}{\eta_{z,c}} \qquad \forall z \in Z, \forall c \in C, \forall t \in T_1 \tag{28}$$

$$l_{z,c,t} = l_{z,c,t-1} + p^{ch}_{z,c,t} \cdot \eta_{z,c} - \frac{p^{dis}_{z,c,t}}{\eta_{z,c}} \qquad \forall z \in Z, \forall c \in C, \forall t \in T \tag{29}$$

$$q^{sto}_{z,c} \cdot 0.5 = l_{z,c,t-1} + p^{ch}_{z,c,t} \cdot \eta_{z,c} - \frac{p^{dis}_{z,c,t}}{\eta_{z,c}} \qquad \forall z \in Z, \forall c \in C, \forall t \in T_{8760} \tag{30}$$

$$0 \leq l_{z,c,t} \leq q^{sto}_{z,c}, \qquad 0 \leq p^{dis}_{z,c,t} \leq q^{con}_{z,c}, \qquad 0 \leq p^{ch}_{m,s,t} \leq q^{con}_{z,c} \qquad \forall z \in Z, \forall c \in C, \forall t \in T \tag{31}$$

Regulatory aspects are considered through the expressions that follow hereafter. The temporal correlation of the generation of renewable electricity and its sourcing to produce electrolytic hydrogen is given through (32). The sum of the sourced electricity in the corresponding timeframe is equal to the one that is generated by additional renewables and that is also assigned for the hydrogen production.

$$\sum_{t}^{T_{bal}} p^{src}_{z,t} = \sum_{t}^{T_{bal}} \sum_{l}^{L} \sum_{g}^{R} p^{pro}_{z,g,t} \qquad \forall z \in Z \tag{32}$$

The generation of renewable electricity is addressed through expression (33). It includes the consideration of geographical requirements through potential regulations. The equation splits the produced renewable electricity into three parts: (1) A part (p_{pro}) that is dedicated for the production of electrolytic hydrogen, (2) a part (p_{inj}) that is surplus electricity and potentially sold to the market to obtain additional revenues and (3) a part (p_{cur}) that cannot be used for any of the two latter two purposes and hence, that is curtailed.

$$q^{res}_{z,l,g} \cdot V^{cf}_{l,g,t} = p^{pro}_{z,l,g,t} + p^{sur}_{z,l,g,t} + p^{cur}_{z,l,g,t} \qquad \forall z \in Z, \forall l \in L, \forall g \in R, \forall t \in T \tag{33}$$

A2. Calculation of levelised costs of hydrogen – LCOH

$$c^{lcoh} = \frac{\left(c^{h2} + C^{sell} - C^{src}\right)}{\sum_z^Z \sum_t^T P_{z,t}^{load,h2}} \tag{34}$$

Where the numerator consists of occurring costs of the hydrogen production and the denominator represents the overall demanded and supplied hydrogen. The costs for the selling of renewable electricity to the market (C_{sell}) and for the sourcing of electricity from the market (C_{src}) are calculate after solving the optimisation of the wholesale electricity market (see (35) and (36)).

$$C^{sell} = \sum_m^M \sum_z^Z \left(V_{m,t}^{mp} \cdot \sum_l^m \sum_g^G P_{z,l,g,t}^{sur} \right) \tag{35}$$

$$C^{src} = \sum_m^M \sum_z^Z \left(V_{m,t}^{mp} \cdot \sum_z^m \sum_g^G P_{z,l,g,t}^{src} \right) \tag{36}$$

A3. Calculation of consumer and producer surplus in the electricity sector as well as the costs for hydrogen

The consumer surplus is calculated by (37). As the electricity demand is assumed to be perfectly inelastic, we set a price cap for the market price in the electricity wholesale market of 3000 EUR/MWh.

$$W^{con} = \sum_m^M \sum_t^T P_{m,t}^{load} \cdot 3000 - \sum_m^M \sum_t^T P_{m,t}^{load} \cdot V_{m,t}^{mp} \tag{37}$$

The producer surplus is determined by (38).

$$W^{pro} = \sum_m^M \sum_t^T \left(\left(\sum_g^G P_{m,g,t} + \sum_s^S P_{m,s,t}^{dis} - \sum_s^S P_{m,s,t}^{ch} \right) \cdot V_{m,t}^{mp} \right) - C^{gen} \tag{38}$$

The total hydrogen costs are calculated by (39).

$$W^{h2} = c^{lcoh} \cdot \sum_z^Z \sum_t^T P_{z,t}^{load,h2} \tag{39}$$

A4. General assumptions

Table 2. General assumptions

Parameter	Value
WACC	8%
Exchange rate	0.89 EUR/USD

A5. Data on power sector representation

Table 3. Considered capacity floors, targets, and caps

Country	Floor			Target	Cap	
	Offshore	Onshore	PV	Nuclear	Hard coal	Lignite
AT	0	9	12	0	0	0
BE	4.4	4.7	10.4	0	0	0
CH	0	0.3	9.8	1.2	0	0
CZ	0	1	3.9	4.1	0	2.9
DE	17	81.5	91.3	0	8	9
DK	6.8	6.2	6.5	0	0	0
FR	5.5	35.9	43.4	59.1	0	0
LU	0	0.4	0.6	0	0	0
NL	11.5	8	27.3	0.5	0	0
NO	0.2	6.1	0.6	0	0	0
PL	5.9	8.7	5.1	0	11.6	7.4
SE	1	16.9	5.4	5.9	0	0
UK	35.2	26.6	23.4	9.3	3.4	0

Table 4. Considered cost parameters[22]

Energy type	Capex [EUR/kW] 2030	Opex fix [EUR/kW]				Opex var [EUR/MWh]			
		1980	2000	2020	2030	1980	2000	2020	2030
Biomass	1800	48.7	48.1	47.5	40.1	3.6	3.6	3.6	3.6
Hard coal	1729	37.8	37.5	37.3	35.4	3.5	3.5	3.5	3.4
Lignite	1867	40.9	40.7	40.5	39.0	3.9	3.9	3.9	3.8
Natural gas - Other	472	16.6	16.5	16.5	16.1	2.1	2.1	2.1	2.1
Natural gas - CCGT	558	21.2	21.1	21.0	20.5	2.2	2.2	2.2	2.1
Natural gas - OCGT	386	11.9	11.9	11.9	11.7	2.1	2.1	2.1	2.1
Nuclear	5250	122.0	121.0	120.0	115.0	6.2	6.3	6.4	7.4
Oil	589	20.7	20.7	20.7	20.7	2.8	2.8	2.8	2.8
Other	1356	31.7	31.6	31.4	30.2	3.2	3.2	3.2	3.1
Other res	1729	37.8	37.5	37.3	35.4	3.5	3.5	3.5	3.4
Peat	1867	40.9	40.7	40.5	39.0	3.9	3.9	3.9	3.8
Waste	1800	48.7	48.1	47.5	40.1	3.6	3.6	3.6	3.6
Ps	0.9	22.8	22.6	21.8	20.3	0.0	0.0	0.0	0.0
Pv	422	16.0	16.0	16.0	13.2	0.0	0.0	0.0	0.0
Onshore	975	18.0	18.0	18.0	17.5	0.2	0.2	0.2	0.2
Offshore	2067	44.5	44.5	44.5	34.5	0.4	0.4	0.4	0.4
Ror	1670	9.0	9.0	8.9	8.2	0.0	0.0	0.0	0.0
Dam	2100	25.5	25.5	25.5	25.5	0.3	0.3	0.3	0.3
Battery	760	27.7	27.0	22.6	15.0	0.0	0.0	0.0	0.0

22 Values for 2020 and 2030 based on (European Commission 2021b) and its underlying data see https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en; Historical values approximated based on various sources; Intermediate values were linearly interpolated

Table 5. Considered technical parameters[22]

Energy type	Efficiency [%]				Lifetime [years]			
	1980	2000	2020	2030	1980	2000	2020	2030
Biomass	35.0	35.0	35.0	39.0	40	40	40	40
Hard coal	37.5	42.3	42.3	44.3	40	40	40	40
Lignite	35.2	38.6	38.7	39.7	40	40	40	40
Natural gas - Other	38.9	44.2	47.3	48.3	30	30	30	30
Natural gas - CCGT	45.0	54.0	58.5	59.5	30	30	30	30
Natural gas - OCGT	32.8	34.4	36.0	37.0	25	25	25	25
Nuclear	33.0	33.0	38.0	38.0	-	-	-	-
Oil	35.0	35.0	35.0	35.0	40	40	40	40
Other	24.2	27.5	42.7	44.1	37	37	37	37
Other res	35.0	35.0	35.0	39.0	40	40	40	40
Peat	35.2	38.6	38.7	39.7	40	40	40	40
Waste	33.0	33.0	35.0	39.0	40	40	40	40
Ps	70.0	70.0	70.0	70.0	-	-	-	-
Pv	-	-	-	-	30	30	30	30
Onshore	-	-	-	-	30	30	30	30
Offshore	-	-	-	-	30	30	30	30
Ror	-	-	-	-	-	-	-	-
Dam	-	-	-	-	-	-	-	-
Battery	92.0	92.0	92.0	92.0	12	12	12	12

Table 6. Considered technical parameter of electrical storage units[23]

Parameter	Storage duration
Pumped storage	48h
Battery	4h

Table 7. Considered fuel emissions[24]

Fuel type	Biomass	Hard coal	Lignite	Natural gas	Nuclear	Oil	Other	Other RES	Peat	Waste
[$tCO2/MWh_{raw}$]	0	0.340	0.397	0.2	0	0.28	0.39	0	0.38	0.39

23 Own assumption
24 Values based on information of Prof. Quaschning - https://www.volker-quaschning.de/datserv/CO2-spez/index_e.php

Table 8. Considered fuel and CO_2 prices[25]

Fuel type / CO_2	Natural gas[26]	Hard coal[25]	Lignite[27]	Nuclear[28]	Biomass[29]	Oil[25]	Waste[30]	Other[31]	CO_2[25,32]
[EUR/MWh_{raw}]/ [EUR/tCO_2]	19.5	7.1	5.6	3.20	31.3	36.2	14.0	20.9	106

Table 9. Considered capacity credits[33]

Fuel type	Value
Biomass	1
Hard coal	1
Lignite	1
Natural gas	1
Nuclear	1
Oil	1
Other	1
Other RES	0.2
Peat	1
Waste	1
Run of river	0.2
PV	0.01
Offshore	0.12
Onshore	0.08
Pumped storage	1
Dam	1

25 Values corrected to EUR2019; USD/EUR Exchange 0.89
26 Values based on (IEA 2021) – Announced Pledges Scenario
27 Values based on (German Federal Network Agency 2019)
28 Values based on average between BE: 3.23 EUR/MWh, UK: 3.49 EUR/MWh and FR: 2.88 EUR/MWh; Data based on (European Commission. Joint Research Centre. Institute for Energy and Transport and SERTIS. 2014)
29 Values based on (German Federal Network Agency 2019)
30 Values based on (German Federal Network Agency 2019)
31 Average between natural gas, hard coal, and lignite
32 No difference between EU ETS and UK ETS
33 Own assumption

A6. Data on hydrogen sector

Table 10. Considered hydrogen demand locations (demand in [kt])[34]

Plant	Postcode	Latitude	Longitude	Application	Value
ArcelorMittal Bremen	28237	53.10309	8.55698	Steel	0.0
ArcelorMittal Duisburg	47137	51.45910	6.85138	Steel	0.0
ArcelorMittal Eisenhüttenstadt	15890	52.12506	14.61731	Steel	0.0
ArcelorMittal Hamburg	21129	53.44390	9.88358	Steel	80.2
ROGESA (Dillinger & Saarstahl)	66763	49.35197	6.67694	Steel	64.9
HKM Duisburg	47259	51.34585	6.60152	Steel	0.0
Salzgitter Peine	38239	52.19835	10.51117	Steel	67.6
Thyssenkrupp Steel Europe Duisburg	47166	51.54955	6.71394	Steel	185.3
BASF Ludwigshafen	6886	51.84341	12.96524	Ammonia	155.6
INEOS Köln	50769	51.09505	6.79096	Ammonia	67.6
SKW Stickstoffwerke Piesteritz	6886	51.84341	12.96524	Ammonia	168.8
YARA Brunsbüttel	25572	53.90678	9.24221	Ammonia	133.3
BASF Ludwigshafen	67063	49.48240	8.40591	Methanol	85.0
Shell Rheinland Raffinerie - Süd	50389	50.77226	6.92255	Methanol	82.3
Ruhr Oel - BP Gelsenkirchen	45896	51.58475	6.98181	Methanol	52.9
Total Raffinerie Mitteldeutschland	6237	51.39492	11.94351	Methanol	132.1
Bayernoil Raffineriegesellschaft	85088	48.79239	11.50131	Raffinery	5.7
BP Raffinerie Lingen	49808	52.46438	7.26746	Refinery	6.3
Guvnor Raffinerie Ingolstadt	85092	48.79332	11.47829	Refinery	6.6
Holborn Europa Raffinerie	21079	53.49622	9.99893	Refinery	6.9
MiRO Mineraloelraffinerie Oberrhein	76187	49.00896	8.32626	Refinery	19.8
Nynas	21079	53.49622	9.99893	Refinery	2.4
OMV Deutschland	85622	48.26674	11.58920	Refinery	4.8
PCK Raffinerie	16303	53.08918	14.25221	Refinery	15.3
Raffinerie Heide	25770	54.20437	9.04484	Refinery	5.7
Ruhr Oel - BP Gelsenkirchen	45896	51.58475	6.98181	Refinery	17.1
Shell Rheinland Raffinerie Werk Nord	50997	50.88831	7.02850	Refinery	12.3
Shell Rheinland Raffinerie Werk Süd	50389	50.77226	6.92255	Refinery	9.6
Total Raffinerie Mitteldeutschland	6237	51.39492	11.94351	Refinery	15.9

34 Values based on (vom Scheidt et al. 2022)

Table 11. Considered parameters of hydrogen storage technologies[35]

Parameter	Unit	GH_2	LH_2	LOHC
Capex base	[EUR]	450	13.31	10
Capex comparison	[kg_{H2}]	1	1	1
Scale	[#]	1	1	1
Ref-Capacity	[kg_{H2}]	1	1	1
Capex scaled	[EUR/kg_{H2}]	450	13.31	10
Capex scaled	[EUR/kWh_{H2}]	13.51	0.40	0.30
Capex scaled	[EUR/MWh_{H2}]	13514	400	300
Opex	[%]	2	2	2
Depreciation period	[y]	20	20	20
Pressure range	[bar]	15-250	-	-
Min filling level	[%]	6	5	-
Boil-off	[%/d]	-	0.2	-

Table 12. Considered parameters of hydrogen conversion and reconversion technologies[35]

Conversion form and activity	Unit	GH_2 Compression	LH_2 Liquification	LH_2 Evaporation	LOHC Hydrogenation	LOHC Dehydrogenation
Capex base	[EUR & EUR/kg_{H2}]	40528 EUR/ kg_{H2}	643700 EUR/ kg_{H2}	900.9 EUR/ kg_{H2} + 2389 EUR	74657 EUR/kg_{H2}	55707 EUR/kg_{H2}
Capex comparison	[kW_{el} | kg_{H2}/h]	1	1	1	1	1
Scale	[#]	0.46	0.67	1.00	0.67	0.67
Ref-Capacity	[kg_{H2}/h]	1030	1030	1030	1030	1030
Capex scaled	[EUR/kg_{H2}/h]	959	63739	903	7393	5516
Capex scaled	[EUR/MW_{H2}]	28793	1914081	27124	221997	165648
Opex	[%]		4	1	4	4
Depreciation period	[a]	4	30	10	20	20
Pressure in	[bar]	15	30		30	
Pressure out	[bar]	30	2	950	0	5
Electricity demand	[kWh_{el}/kg_{H2}]	250	6.78	0.6	0.37	
Heat demand	[kWh_{therm}/ kg_{H2}]	1.707		0	-8.9	9.1
Losses	[%]	0.5	1.625	0	3	1

Table 13. Considered parameters of electrolyser technologies[36]

Parameter	Unit	Alkaline	PEM
Capex	[EUR/kW_{el}]	556	957
Opex	[% of capex per a]	1.5	1.5
Efficiency	[%]	68.0	65.5

35 Values based on (Stöckl et al. 2021a) and (Stöckl et al. 2021b); Assumption that reference facility size of conversion and reconversion units is 1030 kgH_2/h corresponding to values for central applications

36 Values based on (IEA 2020) and (IEA 2019)

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