The cost dynamics of hydrogen supply in future energy systems – A techno-economic study

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The cost dynamics of hydrogen supply in future energy systems – A techno-economic study

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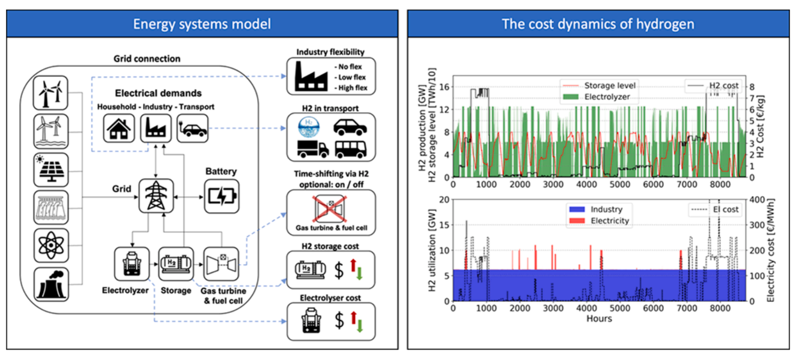
HIGHLIGHTS

- The cost dynamics of hydrogen supply in future energy systems is investigated.
- The cost of hydrogen influenced by several factors, in addition to electricity cost.
- The hydrogen demand profile has a considerable impact on cost of hydrogen.
- Flexibility in the hydrogen demand can reduce the cost by more than 30%.
- Time-shifting of electricity generation via hydrogen provides a system value.

GRAPHICAL ABSTRACT



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ABSTRACT

This work aims to investigate the time-resolved cost of electrolytic hydrogen in a future climate-neutral electricity system with high shares of variable renewable electricity generation in which hydrogen is used in the industry and transport sectors, as well as for time-shifting electricity generation. The work applies a techno-economic optimization model, which incorporates both exogenous (industry and transport) and endogenous (time-shifting of electricity generation) hydrogen demands, to elucidate the parameters that affect the cost of hydrogen.

The results highlight that several parameters influence the cost of hydrogen. The strongest influential parameter is the cost of electricity. Also important are cost-optimal dimensioning of the electrolyzer and hydrogen storage capacities, as these capacities during certain periods limit hydrogen production, thereby setting the marginal cost of hydrogen. Another decisive factor is the nature of the hydrogen demand, whereby flexibility in the hydrogen demand can reduce the cost of supplying hydrogen, given that the demand can be shifted in time.

In addition, the modeling shows that time-shifting electricity generation *via* hydrogen production, with subsequent reconversion back to electricity, plays an important in the climate-neutral electricity system investigated, decreasing the average electricity cost by 2%–16%. Furthermore, as expected, the results show that the cost of hydrogen from an off-grid, island-mode-operated industry is more expensive than the cost of hydrogen from all scenarios with a fully interconnected electricity system.

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1. Introduction

In order to mitigate climate change and reduce the risk of irreversible effects on ecosystems critical for a vigorous planet, anthropogenic fossil greenhouse gas emissions must be reduced and should reach zero by Year 2050, as declared in the Paris Agreement [1]. This means that all sectors must reduce their emissions, and that new fossil-free energy carriers must be applied to enable the continued use of processes that would otherwise entail inherent emissions. Hydrogen is an alternative energy carrier with the potential to enable reductions of emissions in several different sectors, including hard-to-abate sectors, where hydrogen can be used as an energy carrier, feedstock or reactant, in line with the European Hydrogen Strategy [2].

For hydrogen to be implemented and used to reduce emissions, it is important to investigate the cost of hydrogen. A common approach to calculating the cost of hydrogen produced *via* electrolysis is to use the levelized cost of electricity (LCOE) from wind or solar power, together with an assumed cost and capacity factor for the electrolyzer. This approach was used by Longden et al. [3], who concluded that hydrogen could be produced at a cost of 1.76–2.37 $/kg$_{H2}$ from solar PV in Year 2030 or 2.04–2.44 $/kg$_{H2}$ from wind power, depending on the electrolyzer investment cost. In these calculations, capacity factors of 30 % and 45 % were assumed for solar PV and wind power, respectively. The same approach has been used by Bartels et al. [4] and Genk et al. [5], who obtained similar results. However, this approach does not include the dynamics within the electricity system, which is a limitation as it may appear that hydrogen is always available at a certain cost, independently of when and how much hydrogen is required. In addition, it does not allow the possibility to vary hydrogen production with the electricity price using hydrogen storage.

In another study, Lux et al. [6], have investigated the potential to supply future hydrogen demands in Europe by constructing a supply curve for electrolytic hydrogen. Their model minimizes the total system cost, including investments and dispatch of generation technologies, and as an option, the model can choose to produce and sell hydrogen at an exogenously defined cost, thereby reducing the system cost. By varying the cost of hydrogen in this way, the model generates a curve that describes the cost-optimal supply of hydrogen at different hydrogen costs. The results show that more than 1,500 TWh of hydrogen, which correspond to the future levels of hydrogen demand envisioned by the European Commission [7, 8], could be produced at a hydrogen cost of 3.7 €/kg$_{H2}$. However, as this hydrogen demand has neither an hourly demand profile nor a geographic distribution, the model minimizes the cost by producing large volumes of hydrogen during short periods (1,600–2,500 full-load hours on electrolyzers) in regions that have good conditions mainly for wind power to supply low-cost electricity. The assumption of a constant price for hydrogen in the absence of a time-resolved hydrogen demand strongly limits the analysis, as the model will minimize the total cost by producing and selling large volumes of hydrogen during periods of low electricity cost, regardless of whether or not there is a real demand for hydrogen. Thus, this approach will not reflect the cost of hydrogen when and where it is needed, and it neglects the additional costs for the storage and transportation of hydrogen, as well as the additional cost of producing hydrogen during periods with higher electricity costs.

It is clear that the method applied when assessing the cost of hydrogen is important, and that the spatial and temporal resolution of the hydrogen demand can have a considerable impact on the cost of hydrogen as low-cost electricity is not always available, or that the production of hydrogen may be limited by the capacity of the electrolyzer and hydrogen storage. These aspects are included in the work by Vom Scheidt et al. [9], who assessed the hydrogen cost for the German energy system, including hydrogen demands in several sectors. Their work has a high spatial resolution and includes a detailed representation of the entire hydrogen supply chain, giving a hydrogen cost in the range of 2.5–5.5 €/kg$_{H2}$, depending on hydrogen transport mode. However, the model does not include storage of hydrogen, and as the time resolution is limited to 365 time-steps per year, the model does not have the capability to capture hourly variations in hydrogen cost.

An average annual cost for hydrogen, which is commonly used in the litterature, can be a good indicator when comparing different energy systems with regards to what role hydrogen can play and at what cost. However, how the cost of hydrogen supply (including both production and storage cost) varies over time will be an important factor when designing new industries that plan to use hydrogen in their processes. Variation in hydrogen supply cost is likely assuming that the future electricity system will have a high share of variable renewable electricity (VRE) generation, yielding volatility in electricity prices. A time-dependent hydrogen supply cost was briefly presented in our previous work (Öberg et al. [10]), showing that this cost varies significantly over time. However, since our previous work focused on the prospects of hydrogen-fueled gas turbines, the variations in hydrogen production cost were not further analyzed.

Therefore, the aim of this work is to further improve the understanding of the dynamics related to the cost of the hydrogen supply in systems with high shares of VRE. This is accomplished by evaluating the hydrogen production cost on an hourly basis using an energy systems model that endogenously models the hydrogen production cost for different scenarios, varying both the system aspects and technical parameters. We address the following research questions:

- How do the potential future electricity and hydrogen demands, with different levels of flexibility, influence the cost of hydrogen?
- How does the use of hydrogen for time-shifting electricity generation influence: i) the hydrogen cost; and ii) the electricity cost?
- Is it possible for an off-grid electricity and hydrogen supply to satisfy an industrial demand at a lower cost than can be achieved by a grid-connected industry?

2. Method

The linear techno-economic optimization model applied in this work minimizes the total system cost of an energy system, including both electricity and district heating demands. The model includes investments and the dispatch of electricity and heat, where investments are made in generation technologies, electricity transmission technologies, and energy storage technologies. The model was originally formulated by Göransson et al. [11], and subsequently refined by Johansson et al. [12], Ullmark et al [13], and Öberg et al. [10]. A full mathematical description of the model can be found in [10]. In the present work, the model has been further developed by including new demands linked to an assumed future electrification of industrial processes (steel, cement and ammonia), and these demands have different characteristics and levels of flexibility. Explicit assumptions applied to the investigated cases are presented in Section 2.1, and the mathematical formulations for the model development of this work (to account for new industrial demands from electrification of industry) are presented in Appendix A.

In this work, a greenfield approach is applied for Year 2050 for the European continent, which is divided into the European statistical NUTS regions [14]. The greenfield approach means that all investments are made based on the estimated electricity demand for Year 2050, the projected costs for technologies, and a prescribed zero-carbon-emissions cap on generating electricity and heat, which is in line with the ambitions of the European Commission [15]. The currently installed capacities of hydropower and transmission lines in the regions investigated are, however, assumed to be unchanged and are, thus, included in the model.

2.1. Implementation of electricity demands

The electricity demand applied in the model for the investigated

Table 1
Input data for industrial processes considering the electricity and hydrogen demands per tonne of commodity and limitations imposed on flexible operation.

Product	Electricity [kWh/tonne]	Hydrogen [kWh/ton]	*NoFlex* [tonne/h]	*LowFlex* [% of *NoFlex*]	*HighFlex* [% of *NoFlex*]	Ramp rates [% per h]
Steel	816	1,700	Constant	35–115	45–150	20
Ammonia	454	5,979	Constant	70–115	30–150	20
Cement	960	–	Constant	95–105	90–110	2

regions is divided into three categories (traditional, transport, and industry), where the main demand is the so-called 'traditional electricity demand'. This electricity demand is based on historical annual electricity consumption levels in the European countries, obtained from Eurostat [16], and is subjected to an hourly demand profile obtained from ENTSO-E [17]. The electricity demands from transport and industry, which are described in the following subsections, are added to the traditional electricity demand. In this work, it is assumed that the traditional demand will remain at current levels for the coming decades until the Year 2050, and that the demand will retain the current consumption profile. In reality, any eventual activation of demand response within current demands will change the consumption profile, but this is not investigated in the present study. Nonetheless, the investigated scenarios include assumptions as to potential additional future demands from industrial processes and the optimized charging of electric vehicles (EV), which would allow for some flexibility in terms of time-shifting of the electricity demand. The impacts of the assumptions are discussed further in Section 4, and the annual traditional electricity demands per region can be found in Appendix B.

2.1.1. *Electricity for transport*

The future electricity demand for transportation is, in this work, modeled based on the work carried out by Taljegård et al. [18]. While Taljegård and colleagues investigated several different scenarios, in this work, only the scenario in which all road transport units [cars, light trucks (LT), heavy trucks (HT), and buses] are electrified by Year 2050 is considered. The electrification of the transport sector can, in this work, be conducted either entirely *via* direct electrification, or partially *via* indirect electrification using hydrogen as an energy carrier. In both cases, 30 % of the EVs are subjected to an optimized charging pattern (as opposed to direct charging upon arrival), which adds flexibility to the system. When hydrogen use is allowed, a certain share of each vehicle category is indirectly electrified *via* hydrogen (cars, 12 %; LT, 19 %; HT, 28 %; buses, 27 %), according to the European Union Hydrogen Roadmap [19]. It should, however, be noted that the batteries in all the vehicles are modeled as an aggregate battery, a simplification that is necessary to limit the computational effort. The effects of this simplification have been evaluated by Taljegård et al. [20]. Assumptions regarding annual driving demands, hourly driving patterns, and electricity consumption per kilometer are all presented in [18], and the data related to total annual electricity demand is summarized in Appendix C.

2.1.2. *New industrial electricity demands*

Three industrial processes are included in this work, namely, steel, ammonia, and cement production processes, all of which are assumed to be fully electrified by Year 2050. The mathematical implementation of the industrial demands is displayed in Appendix A. The steelmaking process is assumed to be electrified through hydrogen direct reduction of iron ore and electric arc furnaces for the production of crude steel, which according to Fischedick et al. [21] represents the most attractive route for future steelmaking, both from the economic and environmental perspectives. This process requires 1,700 kWh of hydrogen and 816 kWh of direct electricity per tonne of crude steel [22], which corresponds to a total of 3,113 kWh of electricity, assuming electrolytic generation of hydrogen with an electrolyzer efficiency of 74 %. The scenarios investigated in this work assume that steel production remains at current levels, which are taken from Eurofer [23] and are listed in Appendix B for the regions included in this work.

Electrified production of ammonia implies replacing the hydrogen produced from natural gas with electrolytically produced hydrogen. This process has been studied by Fasihi et al. [24], who conclude that the production of one tonne of ammonia requires 5,979 kWh of hydrogen and 738 kWh of direct electricity for the cryogenic separation of nitrogen from air and the compression of both nitrogen and hydrogen (i.e., for a total of 8,817 kWh of electricity). In this work, the energy penalty for compressing hydrogen is, however, included in the general model setup, such that the remaining direct electricity demand for ammonia production is 454 kWh/ton_{NH3}. The currently installed production capacity of ammonia is taken from the work of Egenhofer et al. [25] and is given in Appendix B.

For cement production, it is assumed that a plasma burner will replace the current combustion process, a change that will add a direct electricity demand of 960 kWh of electricity per tonne of cement produced. This value is taken from the work of Klugman et al. [26], in which it is assumed that 1,300 kWh of electricity is required to produce one tonne of clinker, which is then blended with other by-products to generate a clinker-to-cement percentage ratio of 73.7 %. The level of European cement production is assumed to remain at current levels, and the national figures are given in Appendix B.

All three industrial processes can be configured to include different levels of flexibility. The reference option is a constant production rate, where the annual production of steel, ammonia and cement is distributed evenly across all hours of the year, an option referred to as the *NoFlex* scenario (Table 1). The constant production rate is then used as a reference for the options with low and high levels of flexibility. For ammonia and steel production, it is assumed that the upper production capacity in *LowFlex* scenario is 15 % higher than the constant production rate in the *NoFlex* scenario, and 50 % higher in the *HighFlex* scenario. Likewise, a lower limit for ammonia production is assumed, which is based on the work performed by Armijo et al. [27], and set at 60 % of the maximum capacity in the *LowFlex* scenario (0.6 × 115 %), and 20 % of the maximum capacity in the *HighFlex* scenario (0.2 × 150 %). The ramp rate used by Armijo et al. [27] for ammonia production was 20 % per hour. For the minimum production level for steel, Toktarova et al. [28] have suggested 30 % of the maximum capacity, which in the low- and high-flexibility scenarios translates to 35 % (0.3 × 115 %) and 45 % (0.3 × 150 %), respectively. For steel production, a ramp rate of 20 % is assumed. Cement production is assumed to be significantly less-flexible than steel and ammonia production, and flexibility ranges of ± 5 % and ± 10 % are assumed for low flexibility and high flexibility, respectively, both with a ramp rate of 2 % per hour. It should be highlighted here that the flexibility in these industrial processes considers the production rate of the corresponding commodity, and not the flexibility attained through hydrogen storage. The flexibility obtained from hydrogen storage is centralized in each modeled region.

2.2. *Scenarios and assumptions*

The scenarios examined in this work are designed to investigate how different hydrogen demands, hydrogen production technologies, and technology costs affect the cost of hydrogen. The scenarios (S1–S8) are visualized in Fig. 1 and summarized in Table 2. All scenarios include the use of hydrogen in industrial applications, while hydrogen use in transport is only allowed in Scenario 4. Using hydrogen for time-shifting

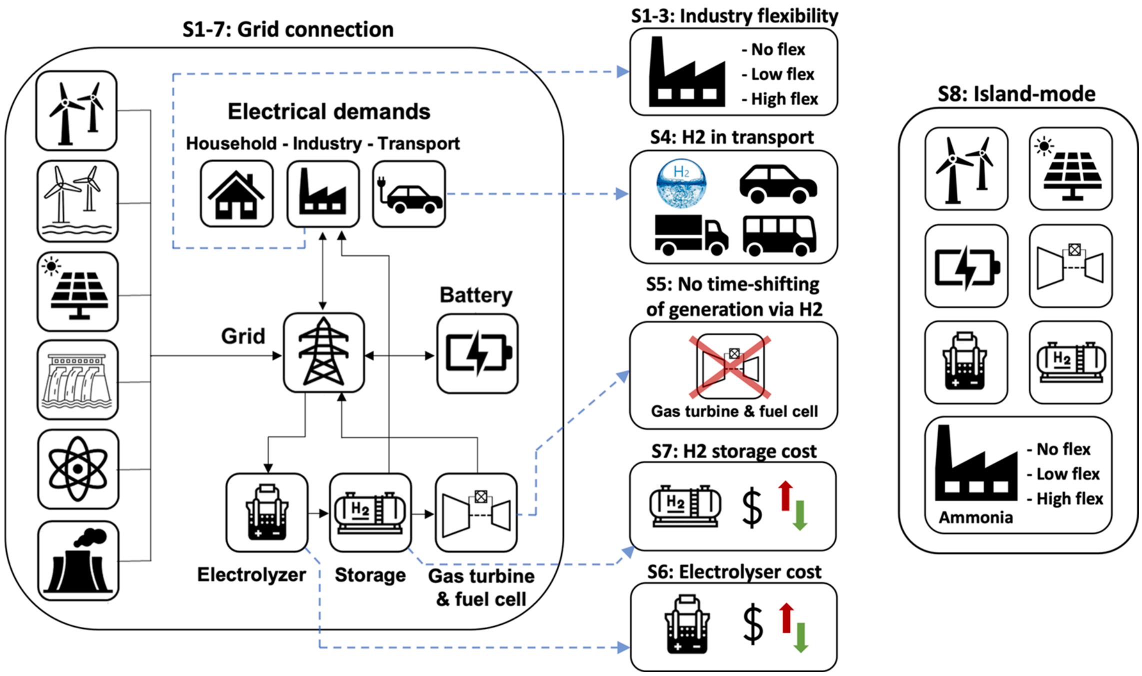

Fig. 1. A schematic overview of the scenarios included in the modeling. Scenarios 1–7 (S1–S7) are connected to the grid, whereas Scenario 8 (S8) investigates island-mode operation of an industrial process. Scenarios 1–3 (S1–S3) investigate the impacts of flexibility in industrial demands, and Scenario 4 (S4) investigates the outcome when hydrogen is used for transportation. What is not shown is that S1–S4 are all run with and without hydrogen production via SMR-CCS. Scenario 5 (S5) assesses the impacts of not allowing for time-shifting of generation through the use of hydrogen, and Scenarios 6 and 7 (S6 and S7) evaluate the impacts of different costs for electrolyzers and hydrogen storage.

Table 2
Modeled scenarios. The subscripts represent the different options given for the parameter that is varied for each scenario.

Scenario	Industry flexibility	H_2 in transport	SMR-CCS[a]	Endogenous H_2 demand	Electrolyzer cost factor	H_2 storage cost factor	Grid connection
$S1_{a\text{-}b}$	*NoFlex*	No	No / Yes	Yes	1	1	Yes
$S2_{a\text{-}b}$	*LowFlex*	No	No / Yes	Yes	1	1	Yes
$S3_{a\text{-}b}$	*HighFlex*	No	No / Yes	Yes	1	1	Yes
$S4_{a\text{-}b}$	*NoFlex*	Yes	No / Yes	Yes	1	1	Yes
$S5_{a\text{-}b}$	*NoFlex*	No	No	Yes / No	1	1	Yes
$S6_{a\text{-}b}$	*NoFlex*	No	No	No	0.75 / 1.25	1	Yes
$S7_{a\text{-}b}$	*NoFlex*	No	No	No	1	0.75 / 1.25	Yes
$S8_{a\text{-}c}$	*NoFlex* *LowFlex HighFlex*	–	No	Yes	1	1	No

[a] SMR-CCS, Steam methane reforming with carbon capture and storage.

electricity generation, where hydrogen is (re)converted to electricity in gas turbines or fuel cells, is allowed in all the scenarios, with the exceptions of Scenarios 5b, 6 and 7.

Scenarios 1–3 investigate the effects of different level of production flexibility within industrial processes that use hydrogen (and direct electricity). These scenarios are all run with and without the option to also invest in hydrogen production from steam methane reforming with carbon capture and storage (SMR-CCS), i.e., with the hydrogen production decoupled from the electricity system [represented by indexes (a) and (b) in Table 2]. For the scenarios that allow investments in SMR-CCS (S1b, S2b, S3b, S4b), the assumed capture rate is 88.5 %, and in order to reach zero emissions, it is assumed that 11.5 % of the fuel input is in the form of biogas, which is assumed to be climate-neutral. The combined cost of natural gas and biogas in the SMR-CCS application is 28 €/MWh.

Scenario 4 investigates the utilization of hydrogen for transport, also with and without the option of hydrogen from SMR-CCS, to assess the impact of an additional hydrogen demand with high peaks in demand without any flexibility. Scenario 5 assesses the value of time-shifting electricity generation through the use of hydrogen and its impacts on both the hydrogen and electricity costs. Scenarios 6 and 7 investigate how different investment costs for electrolyzers and hydrogen storage influence the cost of hydrogen. Finally, Scenario 8 investigates the cost of hydrogen for an industrial demand that is not connected to the grid, i.e., island-mode operation. The industrial process modeled in Scenario 8 is ammonia production (for subsequent use in the production of fertilizer), as it is an industry that is not dependent upon feedstocks such as iron ore and limestone, and is thus not limited to any specific location close to such resources. The assumed annual production of ammonia is 490 kt. This is currently the average size of a plant in Europe [25]. If decarbonized with electricity, this corresponds to a total annual electricity demand of 4.1 TWh, including both direct use of electricity and electricity for hydrogen production.

2.2.1. *Technologies available for investments*

The electricity generation technologies available in the model as investment options are: onshore and offshore wind power, solar PV, gas turbines fueled with biogas and/or hydrogen, and several other types of thermal generation units using different types of fuels (for a full overview of the available power plant options and their corresponding cost structures, see [29]). For the heat demand, industrial heat pumps and electric boilers are included as options, in addition to combined heat and

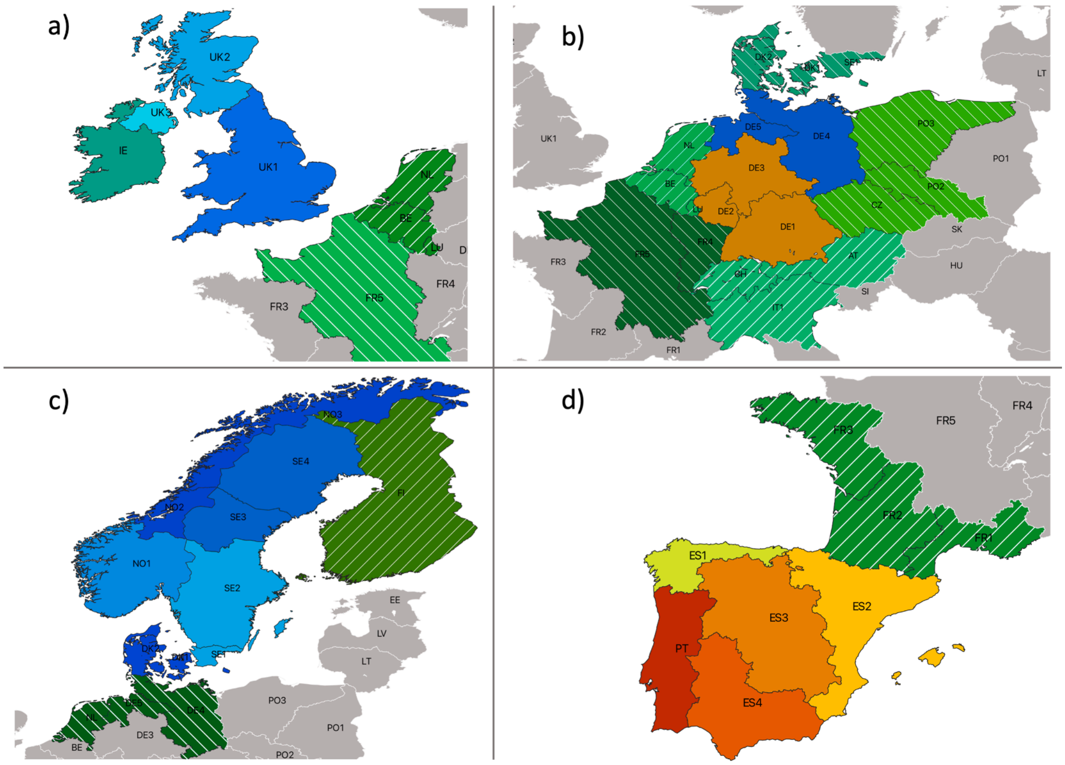

Fig. 2. The four regions applied in the modeling are: a) British Isles plus European shoreline of the English canal; b) Central Europe; c) the Nordic countries; and d) the Iberian Peninsula. The color-coding indicates the regions modeled, which can be actual NUTS2 regions or a cluster of NUTS2 regions. The regions indicated in green with diagonal white lines are boundary regions for trade, which are not analyzed in the present study.

power plants, although heat storage units are not included. Both batteries and hydrogen storage are included as options for energy storage, where hydrogen storage distinguishes between lined rock caverns (LRC) and salt caverns. The European potential for using salt caverns is taken from the work of Caglayan et al. [30]. For the production of hydrogen, electrolyzers are available in all the scenarios, and as previously described, some scenarios allow for investments in SMR-CCS. The electrolyzer efficiency is assumed to be 74 %, based on [31]. For (re) conversion of hydrogen to electricity, the model include fuel cells and hydrogen-fueled gas turbines, which include both open cycle (OCGT) and combined cycle gas turbines (CCGT). Finally, the model includes the possibility to invest in new transmission capacity, in addition to the already existing transmission capacity.

The investment cost of hydrogen-fueled gas turbines is taken from a previous work [32], whereby the investment cost is assumed to increase with an increasing upper limit for hydrogen mixing. A sensitivity study on the impact of the investment cost for hydrogen-fueled gas turbines is presented in [10]. The complementary fuel to hydrogen used in hydrogen-fueled gas turbines is biogas, which in the model is assumed to be produced from solid biomass. The biomass cost is assumed to be 60 €/MWh, which in the case of conversion to biogas gives a cost of 106 €/MWh, which includes both the energy penalty and the investment cost of a gasification plant.

Since this work is limited to modeling the electricity system, which is not considered a hard-to-abate sector, bioenergy carbon capture and storage (BECCS) is not included in this work. As such, it is assumed that BECCS is a technology that is only to be used to create negative emissions to compensate for residual emissions in “hard-to-abate” sectors, such as aviation and agriculture.

2.2.2. Geographic scope

In this study, four different European regions are modeled (Fig. 2), with the regions having different potentials for wind, solar, and hydropower; the data for wind and solar capacities and generation are taken from the work of Mattson et al. [19]. These regions are modeled separately and consist of six to seven sub-regions, where the green sub-regions with diagonal white lines are boundary regions that are included to facilitate the import and export of electricity to the focus regions (colored blue, yellow, orange, or red). While all of the sub-regions are fully modeled for all the scenarios described in Table 2, the results for the boundary regions are not explicitly analyzed. The focus regions of the British Isles and the Iberian Peninsula are color-coded according to the statistical NUTS2 regions, whereas most of the other sub-regions are formed by a number of clustered NUTS2 regions. For Germany (Fig. 1b), the northern part (with extensive wind resources) is constituted by DE4 and DE5, while the southern part (with large solar resources) is composed of DE1–DE3. In the Nordic countries, Denmark is modeled as one region (DK1 and DK2), and both Sweden and Norway are represented by a northern part and a southern part, as indicated by the color-coding in Fig. 1c.

2.2.3. The average cost of electricity

The average cost of electricity and hydrogen, which is used as a complement to the time-resolved electricity and hydrogen costs, is calculated according to Equation (1), where the marginal cost of electricity or hydrogen per time-step (t) is weighted by the amount of electricity or hydrogen generated in each time-step.

$$c_{ave} = \frac{\sum_t (c_{marg,t} \bullet g_t)}{\sum_t (g_t)} \quad (1)$$

3. Results

The results are presented in four sections, where the first section focuses on the dynamics of the hydrogen supply cost, and the second section highlights the value of shifting electricity generation in time through the use of hydrogen. The third section presents the impacts on electrolyzers and hydrogen storage of SMR-CCS hydrogen production

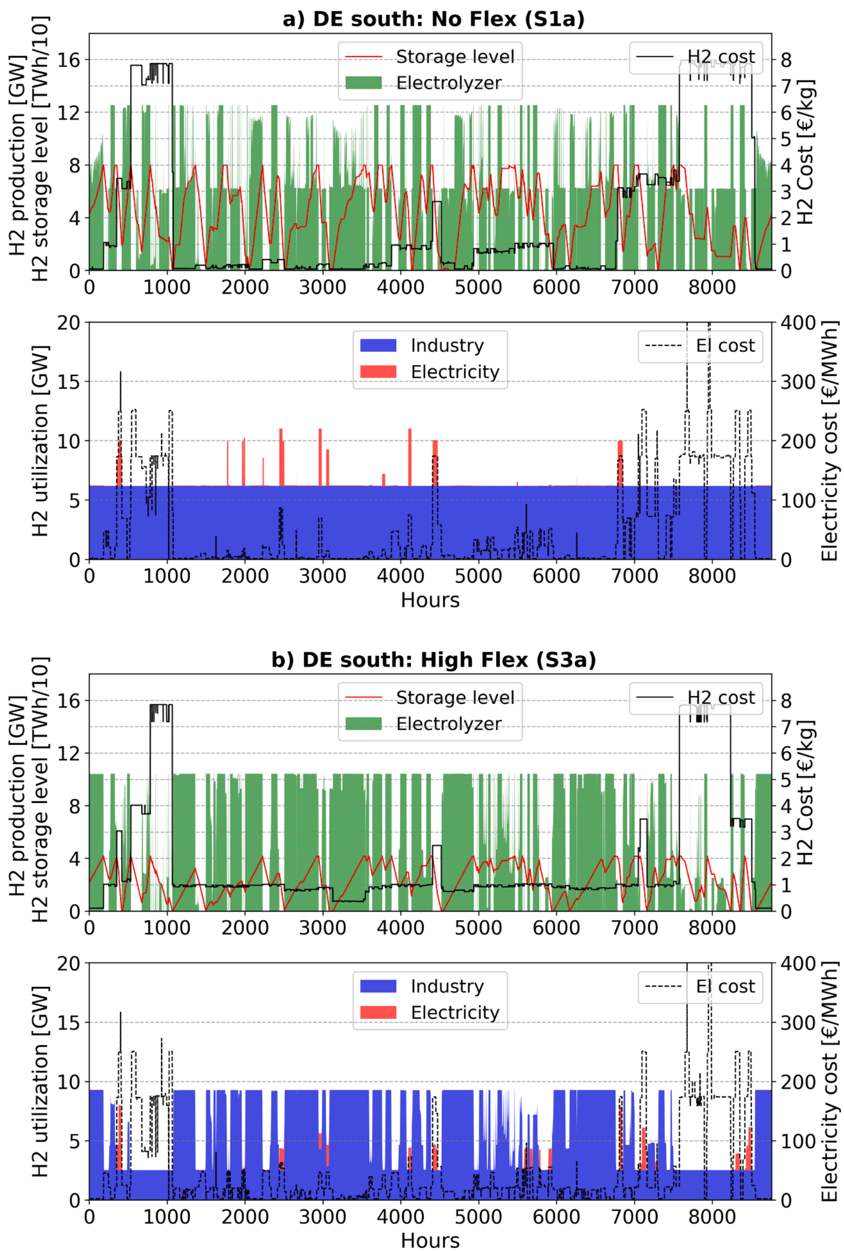

Fig. 3. The production and utilization of hydrogen in southern Germany (DE South) for two scenarios with different levels of flexibility in industry: Scenario 1a, with no flexibility; and Scenario 3a, with high-level flexibility.

and a sensitivity analysis of the investment costs. Finally, the fourth section compares the cost of hydrogen in off-grid, island-mode configurations to grid-interconnected energy systems.

3.1. The dynamics of hydrogen supply cost

Fig. 3 displays the time series from the modeling results for Scenario 1a with a constant industrial demand (Fig. 3a) and for Scenario 3a with high flexibility in industry (Fig. 3b). The upper panels in Fig. 3 plot the level of hydrogen production, the hydrogen storage level, and the marginal cost of supplying hydrogen. The lower panels plot the utilization of hydrogen, together with the cost of electricity. As mentioned above, the cost of hydrogen is the marginal cost of supplying one additional unit of hydrogen for each individual time-step. Thus, this cost may take into consideration, depending on the situation in a particular time-step, the additional costs associated with investing in larger electrolyzer capacity, larger storage capacity, and operating the electrolyzer during periods with higher electricity cost, as well as the alternative cost for shifting the industrial hydrogen demand in time in scenarios that allow this option.

It can be seen in Fig. 3 that the marginal cost of hydrogen is linked to the marginal cost of electricity, such that a high electricity cost results in a high marginal cost for hydrogen, which is as expected. It is, however, noteworthy that during the hours around Hour 4,200 in Fig. 3a, the cost of hydrogen is about 0.8 €/kg, despite the electricity cost being close to zero. This is due to the fact that the electrolyzer is operating at full capacity, so if more hydrogen should be produced during this period, a larger investment in electrolyzer capacity would be required.

The system cost-optimal hydrogen storage capacity has an impact on the marginal cost of hydrogen because during long periods of low electricity cost it can limit hydrogen production. For instance, at the very beginning of the year (Fig. 3a), hydrogen production is sufficient to supply both the industrial demand and to fill the storage units, despite the electrolyzer only operating at part-load. In Hour 200, the electricity

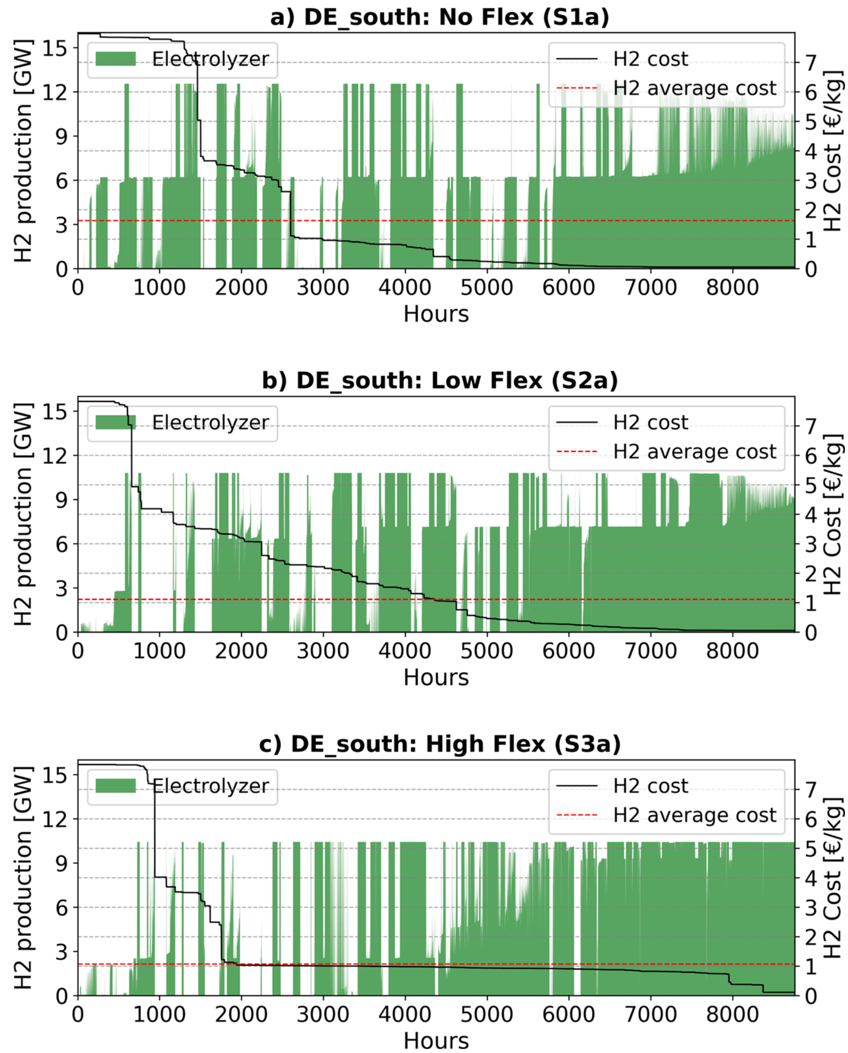

Fig. 4. Cost durations for hydrogen and the corresponding hydrogen production levels for Scenarios 1a – 3a for southern Germany.

cost increases, which leads to a concomitant increase in the hydrogen cost, although in this case, the hydrogen cost increase is not due solely to the increased electricity cost. The marginal cost of hydrogen is here also affected by the option to invest in larger storage capacity. Such an investment would enable the electrolyzer to produce more hydrogen during the low-cost electricity period, and thereby avoid producing hydrogen during other periods when the electricity cost is higher, which for instance occurs around Hour 300 and Hour 500. The periods before the hydrogen storage is completely full typically have a low marginal cost of hydrogen (see for example Hours 3,100–3,500), since neither the electrolyzer nor the hydrogen storage is operating at full capacity. This can be explained by the facts that: i) the electrolyzer is not required to be operated at full capacity to fill the storage before the electricity cost increases; and ii) the hydrogen demand is assumed to be fixed, so the system cannot make use of additional low-marginal-cost hydrogen during this period.

With the flexibility of the assumed hydrogen demand (Scenario 3a) shown in Fig. 3b, for which there is a high level of flexibility in the industrial processes, there are smoother variations in the marginal cost of hydrogen compared to the non-flexible case in Scenario 1a, i.e., the production of hydrogen during periods of high electricity cost can be significantly reduced. One additional effect when introducing flexibility in the hydrogen demand is that the marginal cost of hydrogen is also affected by the alternative cost of producing the industrial commodity at another time. This is seen in Fig. 3b for the period between Hour 2,100 and Hour 3,100, where three different levels of marginal costs for hydrogen can be identified, despite there being similar conditions regarding electricity cost, electrolyzer operation, and hydrogen storage level.

To analyze further the marginal cost of the hydrogen supply and the impacts of different levels of flexibility of the hydrogen demand, cost duration plots for Germany (region DE South) are presented in Fig. 4, which shows the sorted marginal cost of hydrogen and the corresponding electrolyzer operation, together with the weighted annual average cost for the hydrogen supply. It is clear that when there is no flexibility in the industrial hydrogen demand the electrolyzer is operated mainly at part-load during the period with the lowest hydrogen cost (Fig. 4a). Compared to the scenarios in which there is flexibility in the industry (Fig. 4b and 4c), a significant amount of hydrogen is produced when the marginal cost of hydrogen is greater than 7 €/kg$_{H2}$. Since the annual average cost of hydrogen is similar for the scenarios with low and high levels of flexibility in industry, it can be concluded that a rather low level of flexibility may be sufficient to have a significant impact on the hydrogen cost, and that increased flexibility renders diminishing returns.

Fig. 5 presents the results for Scenarios 1a–4a, i.e., the outcomes from different characteristics of hydrogen demand, for one selected subregion per modeled region (see Fig. 2). Comparing the annual average hydrogen costs, it is clear that the impact of flexibility in industry is low in UK1 (Fig. 5a), as compared to the other regions presented (Fig. 5b-d)

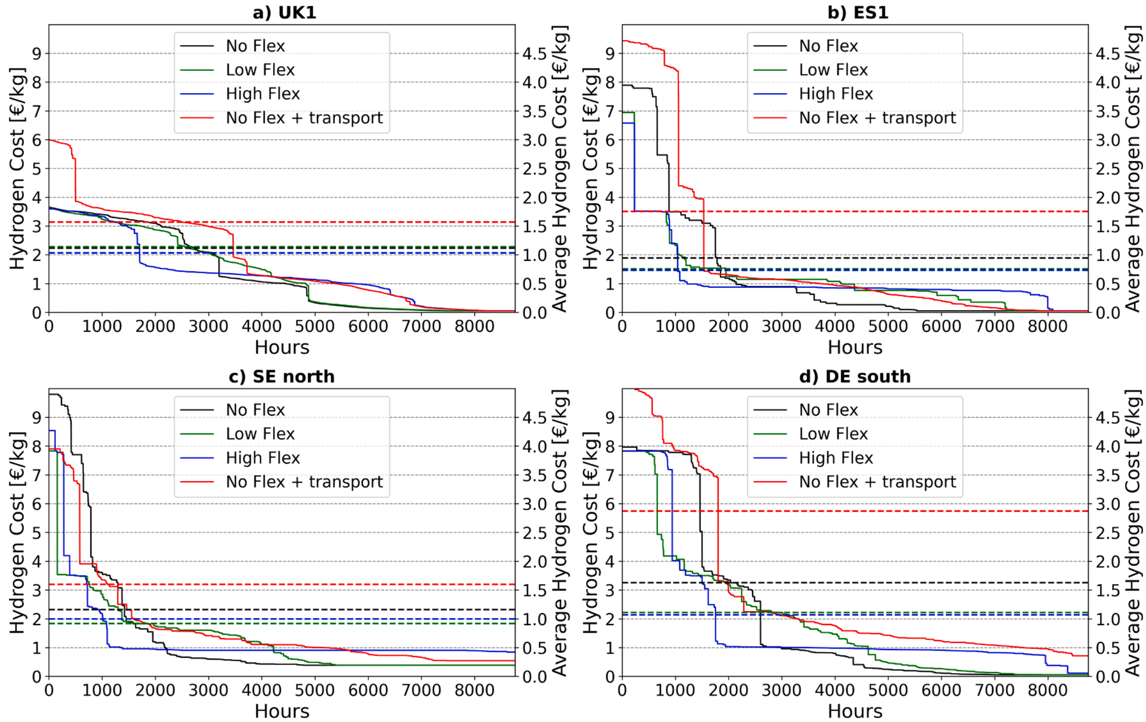

Fig. 5. Cost durations of the marginal supply cost of hydrogen for Scenarios 1a – 4a, which are scenarios with different levels of: flexibility in industry (Scenarios 1a – 3a); and hydrogen use in transport (Scenario 4a). The index a indicates that only electrolytic hydrogen is allowed. The results are shown for one selected subregion in each of the four regions included in the modeling (Fig. 2).

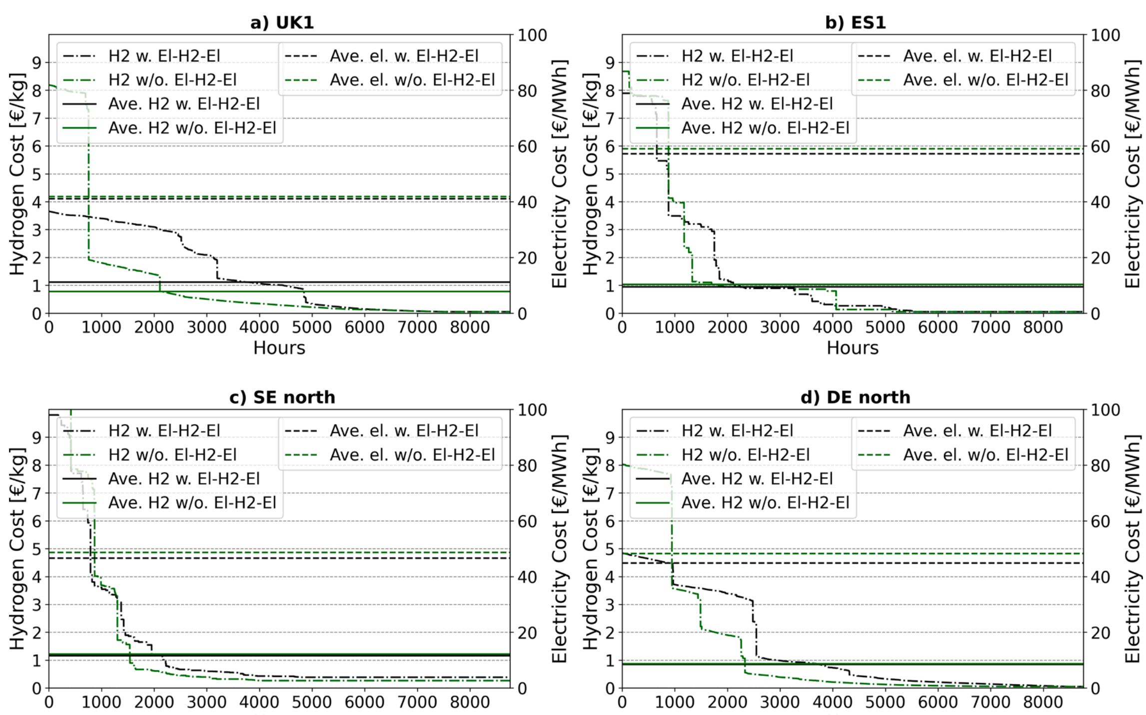

Fig. 6. Comparison of the annual average electricity and hydrogen costs when time-shifting of electricity generation is allowed (Scenario 5a) or not allowed (Scenario 5b).

where a significant drop in the annual average hydrogen cost is observed when flexibility is allowed. However, the additional hydrogen demand assumed for Scenario 4a, which includes hydrogen for transport, causes the average hydrogen cost to increase significantly in all the regions presented in Fig. 5. The reason to this cost increase is to some extent an increased hydrogen demand, and consequently a stronger demand for electricity, which is mainly supplied from VRE with a lower capacity factor given that the best sites are already occupied. However, the characteristics of the hydrogen demand for the transport sector are also significantly different than those in the industry, consisting of frequent

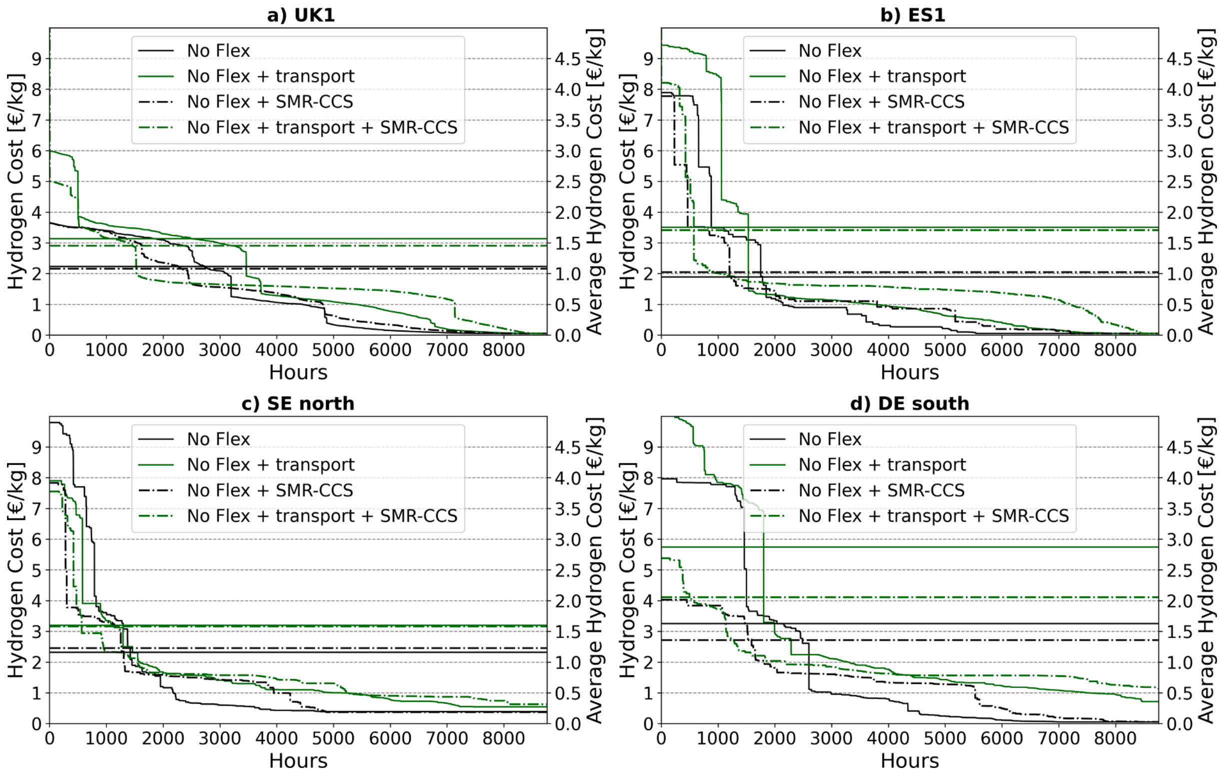

Fig. 7. The impact of allowing hydrogen production from SMR-CCS in Scenarios 1 and 4, where Scenario 1 models an industry with no flexibility, and Scenario 4 includes hydrogen utilization in the transport sector.

peaks of high amplitude, up to sixfold higher than the industrial demand level. The effect of this type of hydrogen demand is that the hydrogen is to a greater extent supplied on-demand, which means that there is reduced use of hydrogen storage to avoid high-cost electricity hours. For southern Germany, the hydrogen demand is four-times higher when hydrogen is used for transport, compared to when it is not, while the installed electrolyzer capacity is only increased by a factor of three. This increases the full-load hours of the electrolyzer by 32 %, from 4,492 h to 5,909 h, which entails operating during more high-electricity-cost hours. Furthermore, the hydrogen storage capacity is only 64 % larger when hydrogen is used in transport, which indicates that it is too costly to smoothen the hydrogen production profile and avoid high electricity-cost hours when the demand consists of such frequent peaks of considerable amplitude.

3.2. The value of time-shifting of generation via hydrogen

Scenarios 5a and 5b assess the value of shifting electricity generation in time using hydrogen production, storage, and reconversion back to electricity, where Scenario 5a allows for hydrogen reconversion technologies such as hydrogen-fueled gas turbines and fuel cells, whereas Scenario 5b does not. The results, presented in Fig. 6, clearly show that the average electricity cost is lower when time-shifting of electricity generation using hydrogen is allowed. Therefore, time-shifting *via* hydrogen does provide a value to the system, despite a relatively low round-trip efficiency (in the order of 30 %–40 % depending on the reconversion technology) and the availability of stationary batteries and flexible charging of EVs. This since variations that are irregular and longer in duration (typical variations from wind power) are too costly to be balanced with batteries, as is described in [10]. The annual average electricity cost is decreased by 2 %–7% in the regions presented in Fig. 6 when time-shifting *via* hydrogen is allowed, although for southern Sweden, the average cost reduction is 16 %.

From Fig. 6, it can also be seen that it is only in UK1 (Fig. 6a) that the average cost of hydrogen increases when time-shifting *via* hydrogen is allowed (Scenario 5a), as compared to when time-shifting is not allowed (Scenario 5b). This is understandable considering that time-shifting *via* hydrogen is highly competitive in UK1, as compared to the other regions. For the other regions shown in Fig. 6, the average hydrogen cost is similar for Scenarios 5a and 5b, albeit with different cost profiles over the year.

It should be mentioned that the reconversion of hydrogen back to electricity not only occurs during the hours with the highest electricity cost, but also during periods with moderate costs for electricity (lower panels of Fig. 3, a and b). Thus, during long periods with low electricity costs, i.e., when there is excess capacity in electrolyzers and hydrogen storage units, low-cost hydrogen can occasionally be used to balance small variations in the electricity cost, as soon as there is a sufficient cost difference to cover the round-trip efficiency losses. The hydrogen reconversion technology that appears most frequently in the model results is CCGTs with 100 vol-% hydrogen capability, whereas no investments in fuel cells are obtained given the assumed costs for these technologies.

3.3. Impact of SMR-CCS and hydrogen technology cost

The option of hydrogen production *via* SMR-CCS is included in Scenarios 1b–4b (Table 2). The results show that hydrogen production that is decoupled from the electricity system has a limited impact on the cost of hydrogen in most of the scenarios and regions. Investments in SMR-CCS are primarily seen when there is no flexibility in industry (Scenario 1b) and when hydrogen is used in transport (Scenario 4b). The exception is southern Germany, which is a region that obtains investments in SMR-CCS in all of Scenarios 1b–4b. The impact on the hydrogen cost when allowing for SMR-CCS is shown in Fig. 7; it is evident that the impact is limited in both Scenarios 1b and 4b for UK1, ES1, and northern Sweden. For southern Germany, the impact on the hydrogen cost is more-pronounced, especially when hydrogen is used in

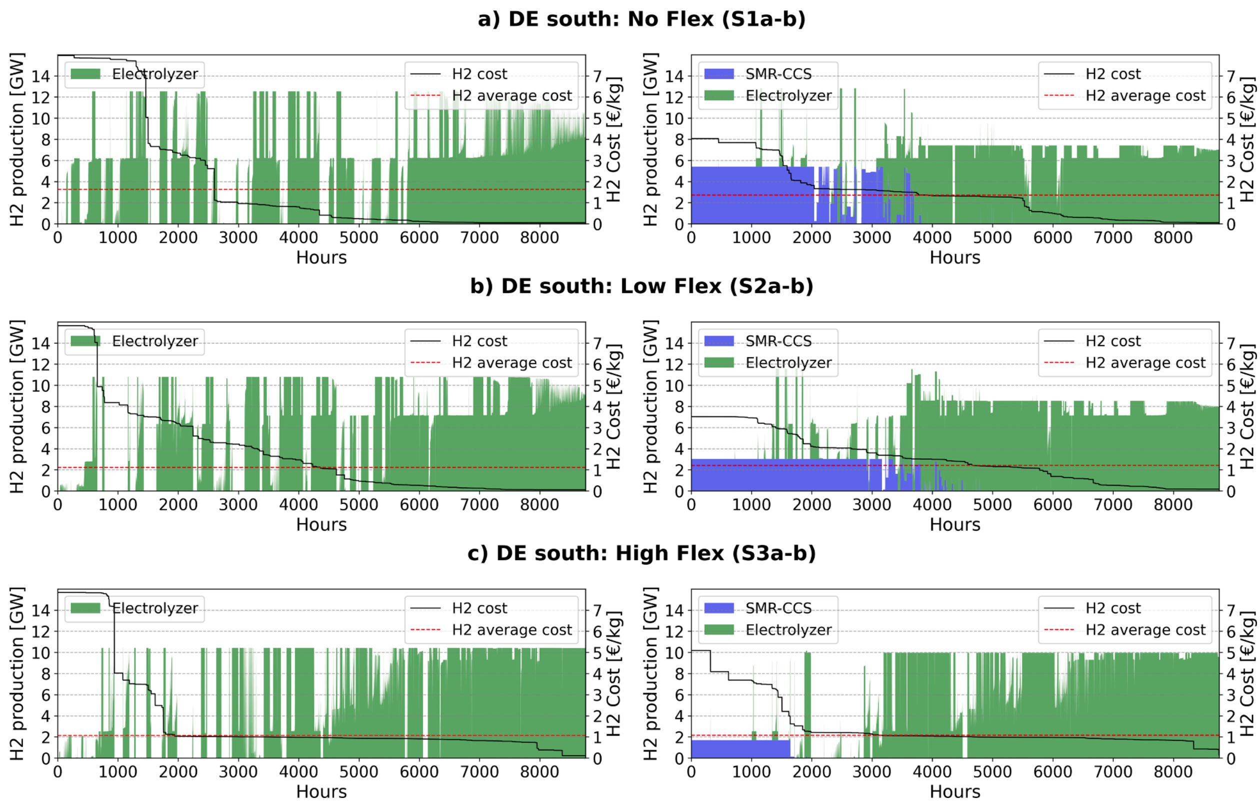

Fig. 8. Hydrogen cost durations and hydrogen production levels in southern Germany for Scenarios 1a-b, 2a-b, and 3a-b, where index a only includes electrolytic hydrogen, and index b includes also hydrogen production from SMR-CCS. It should be mentioned that the panels to the left are the same as those in Fig. 4, and are included here to make the comparison easier.

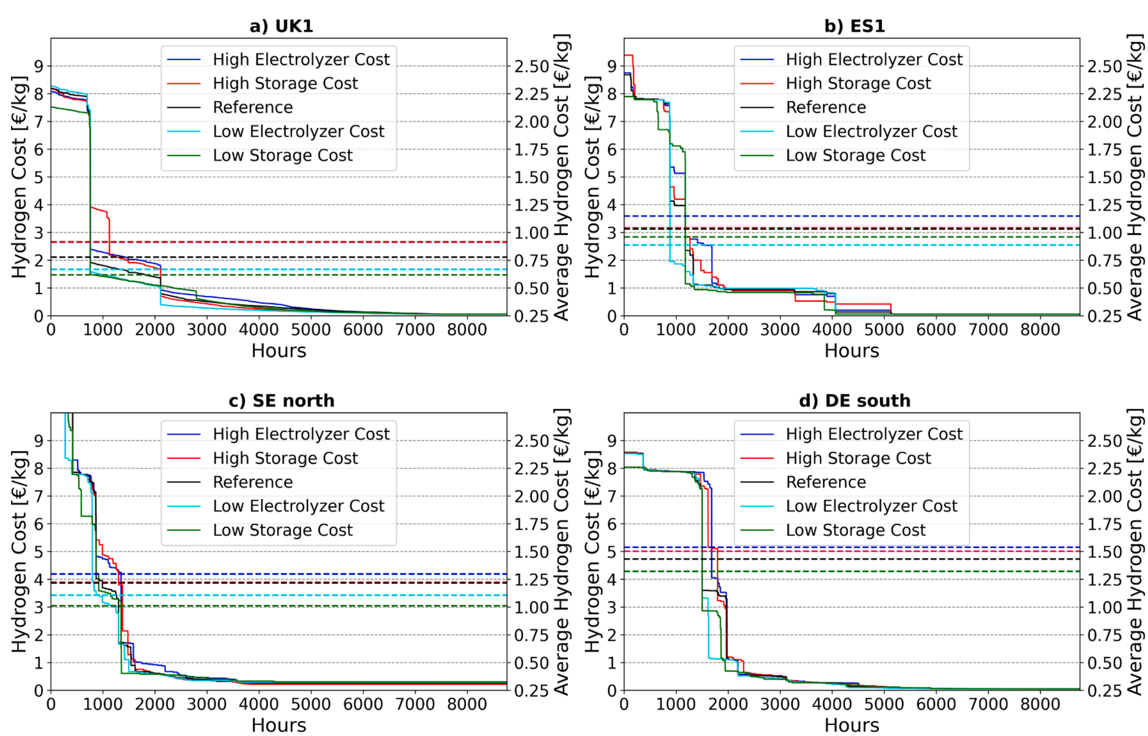

Fig. 9. The hydrogen costs for the four regions when the investment cost for electrolyzers and hydrogen storage is increased or decreased, according to the descriptions of Scenarios 6 and 7. The reference scenario is Scenario 5b.

Table 3
Summary of the changes in annual average hydrogen cost that occur when the investment cost for electrolyzers and hydrogen storage is increased or decreased ± 25 %.

	UK1		ES1		SE North		DE South	
Technology cost	[€/kg_{H2}]		[€/kg_{H2}]		[€/kg_{H2}]		[€/kg_{H2}]	
Electrolyzer: high	0.91	+17 %	1.15	+12 %	1.30	+7%	1.54	+8%
Storage: high	0.91	+17 %	1.04	+0.1 %	1.22	–	1.50	+5%
Reference	**0.78**	**–**	**1.03**	**–**	**1.22**	**–**	**1.43**	**–**
Electrolyzer: low	0.67	−14 %	0.89	−14 %	1.11	−9%	1.32	−8%
Storage: low	0.62	−21 %	0.96	−7%	1.01	−17 %	1.32	−8%

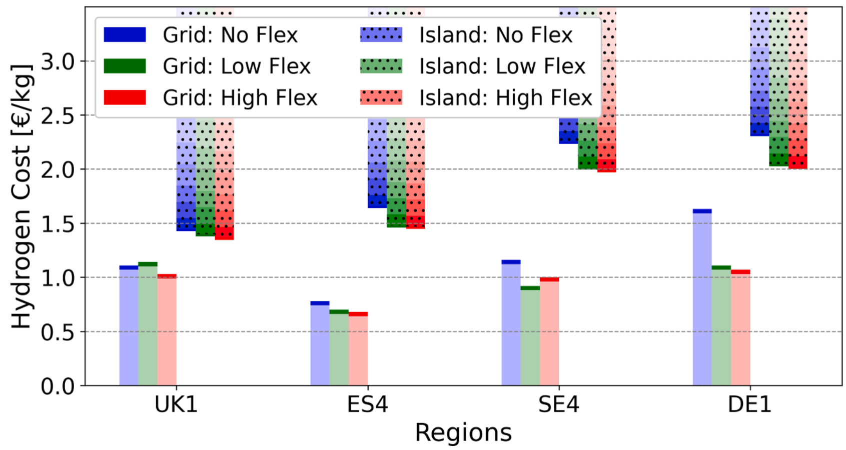

Fig. 10. Comparison of the annual average hydrogen costs between a grid-connected system and an industry that is not connected to the grid, operating in island-mode. The results show that even with the best wind and solar PV sites, island-mode operation always reaches a higher hydrogen cost than a fully interconnected energy system.

transport (Scenario 4b). The operation of SMR-CCS in southern Germany and its impact on the hydrogen cost are displayed in Fig. 8; it is clear that the majority of the hydrogen is still produced from electrolysis (*NoFlex*: 72 %; LowFlex: 81 %; HighFlex: 95 %), and that the competitiveness of SMR-CCS is reduced when flexibility within industry is introduced. Furthermore, the competitiveness of SMR-CCS is affected by the cost of natural gas, which is discussed further in Section 4.

It should be noted that in some regions, the average hydrogen cost is increased when SMR-CCS is allowed (Fig. 7, b and c). This occurs because the model minimizes the total system cost, and not the hydrogen cost. Thus, SMR-CCS can be used in one or several of the sub-regions modeled, reducing the demand for electricity in general, and in particular during hours with an already high electricity cost. Thus, it can change the optimal solution for export and import of electricity between the regions modeled, which may affect the cost of hydrogen also in regions that do not secure investments in SMR-CCS.

Scenarios 6a-b and 7a-b illustrate the impacts from increased and decreased investment costs for electrolyzers and hydrogen storage. This is accomplished by varying these investment cost by ± 25 % (i.e., the possibility for endogenously obtained production of hydrogen to balance the electricity system is removed in the model). The results, which are shown in Fig. 9 and Table 3, show that in systems where the cost of hydrogen is high, and consequently the system itself results in a high hydrogen cost, the investment cost for electrolyzers and hydrogen storage has a more limited impact, as compared to systems with a low average hydrogen cost. This can be seen by comparing the results for UK1 with those for southern Germany in Fig. 9 and Table 3. From the results obtained, it is difficult to draw any conclusions regarding which investment cost for the two technologies (electrolyzer or hydrogen storage) has the strongest impact on the hydrogen cost.

3.4. Hydrogen cost in island-mode operation

Fig. 10 shows that the cost of hydrogen in an isolated system is higher than the hydrogen cost in a fully interconnected systems, and that this is true for all the scenarios and for all the regions investigated. The hydrogen costs for the off-grid systems (Scenarios 8, a–c) are plotted to show an increasing value as the bar is fading upwards from the lowest cost attained in the optimization. This is done to indicate that even if the best wind and solar PV sites can be used by the industry in an off-grid system, the hydrogen cost is at least 21 % higher (UK1, *LowFlex*) than that for a grid-connected system. However, as these potential off-grid operated industries will have to co-exist with the rest of the system, the best wind and solar PV locations will likely already be occupied. Therefore, the hydrogen cost for the isolated industries will likely be even higher. The average hydrogen costs for grid-connected systems are shown only for the optimal solution, highlighted at the top of each of the faded bars, as it is considered unlikely that an entire electricity system would not make use of the best VRE sites available. The resulting investments in Scenarios 8, a–c can be found in Appendix D.

As shown in Fig. 11, off-grid hydrogen is produced during most of the year without any longer disruptions. This is different from hydrogen production in grid-connected systems (Fig. 4), where electrolyzer operation is frequently disrupted to minimize the use of high-cost electricity, and instead, hydrogen is overproduced during low-cost electricity periods and supplied from storage units when the electrolyzer is not in operation. In an off-grid scenario, only two actions can be used to minimize the total cost for hydrogen: i) minimizing off-grid electricity production and producing hydrogen also during high-cost electricity hours (e.g., during night time in solar-dominated regions); and ii) investing in overcapacity of electricity generation and electrolyzer capacity in combination with hydrogen storage. The former option minimizes the curtailment of electricity and investments in hydrogen storage, whereas the latter aims to invest in overcapacity of the electrolyzer to be used during periods with higher levels of electricity generation, which is an option that requires greater investments in hydrogen storage and curtailment of electricity that cannot be sold. Given the assumed costs for wind and solar power, as well as for

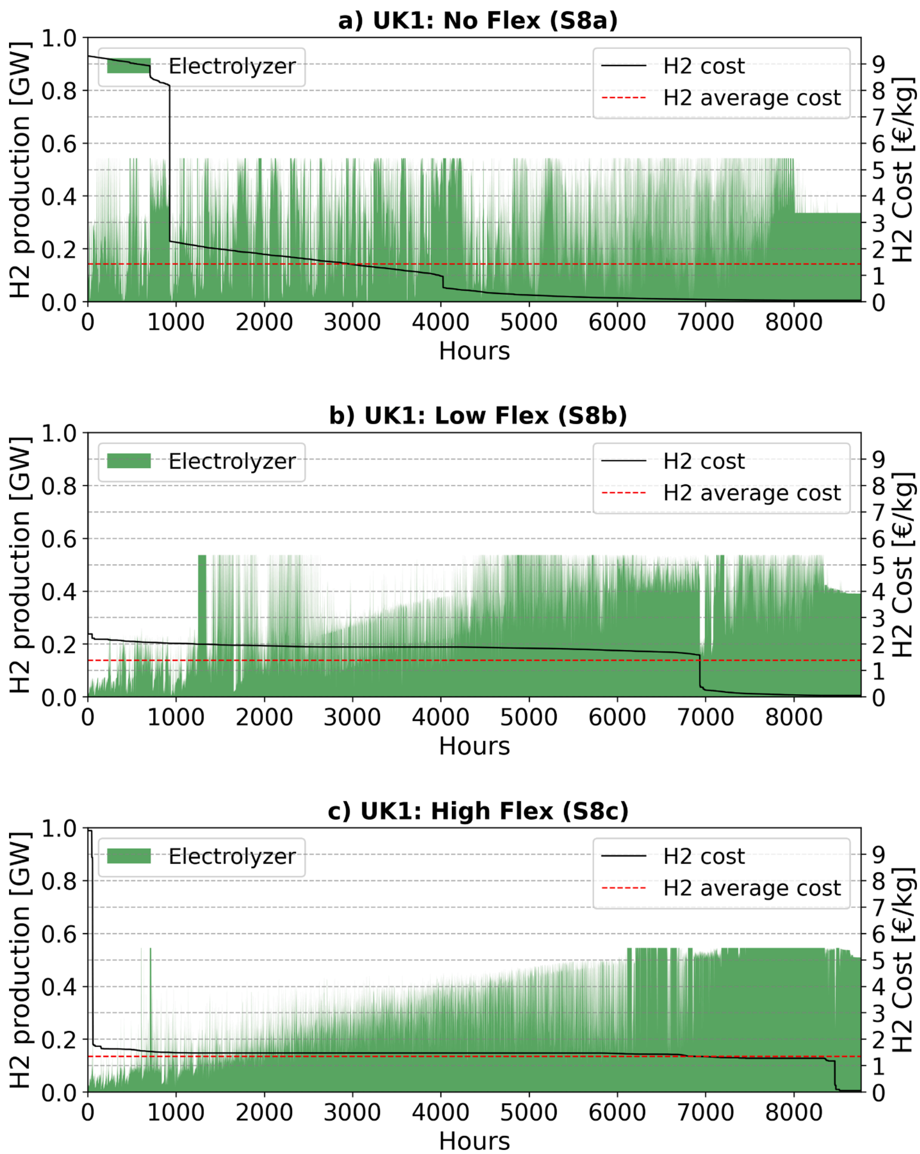

Fig. 11. Hydrogen cost durations for off-grid operation of an ammonia production industry for Scenarios 8, a-c in UK1.

hydrogen storage, it can be concluded that the first option above is the most cost-effective design for an off-grid system, although it results in hydrogen being supplied at a cost that is significantly higher than in a grid-connected system, as concluded in the previous paragraph. It should here be highlighted that, as the assumed annual electricity demand for the off-grid industry is 4.1 TWh, the required mix of investments in wind and solar capacity is considerable, including up to 1 GW of wind power in most scenarios, and up to 1.4 GW of solar power in the regions with the best solar resources, as can be seen in Table D.1 in Appendix D.

The results clearly show that supplying hydrogen in an off-grid system is more costly than in a grid-connected system. However, the scenarios compared in Fig. 10 do not include the use of hydrogen in transport (Scenario 4), which is a scenario that yields a significantly higher hydrogen cost due to the characteristics of the hydrogen demand. In such a scenario, it would be an attractive option for an industry with a high demand for hydrogen to disconnect from the grid and operate in island-mode. Combining the results from Figs. 5 and 10, it is evident that the likelihood of such an action being taken differs across the regions analyzed. In UK1, where the average cost of hydrogen in Scenario 4a reaches a level slightly above 1.5 €/kg_{H2} (Fig. 5a), there is probably no benefit for an industry to operate in island-mode. This is the case because the best outcome from island-mode operation in UK1 is an average hydrogen cost of slightly less than 1.5 €/kg_{H2} (Fig. 10), assuming that the most-favorable wind and solar PV locations are used, which is unlikely as there will still be an electricity system supplying the remaining electricity and hydrogen demands, and thus competing for the best VRE-generation locations. In DE1, the prospect of an off-grid industry is somewhat more promising. The average hydrogen cost reaches almost 3 €/kg_{H2} in Scenario 4a (Fig. 5d), whereas the best hydrogen cost in island-mode is around 2 €/kg_{H2} (with some flexibility within the industry process). Therefore, it would be possible for an off-grid system to be competitive even if the best locations for VRE generation would not be available.

4. Discussion

The present work shows that the cost of supplying electrolytic hydrogen including both the production and storage costs, varies significantly over time, which is due to the fact that the electricity system investigated has large shares of VRE. Thus, the results from this work extend substantially the previous works of Longden et al. [3], Bartels et al. [4] and Genk et al. [5], since they did not sufficiently represent the variability of the cost of hydrogen. Furthermore, in the present work, the characteristics of the hydrogen demand are proven to have a substantial impact on the cost of hydrogen, especially in a situation where a varying hydrogen demand with inflexible peaks in demand, which in this study is represented by hydrogen for transport, causes a significant increase in the cost of the hydrogen supply.

Considering the assumptions made regarding flexibility within industrial processes, Scenarios 2 and 3 assume that overcapacity is available within the industries, although the model does not account for the additional cost of this overcapacity. The aim of this implementation is to evaluate the impact that a flexible hydrogen demand would have on the cost of hydrogen. It is concluded that it would lead to a lower hydrogen cost, which would benefit a hydrogen-dependent industry. It is acknowledged by the authors that such overcapacity will influence the cost of the produced commodity (e.g., steel, cement, or ammonia), and that the modeled scenarios would not necessarily be the optimal solutions for the industry. However, the analyzed scenarios assume that the same annual demand has to be supplied, even when flexibility is allowed. This means that in the case with low flexibility, more than 7,600 full-load hours are still attained for an industry with 15 % overcapacity. Furthermore, it is acknowledged that industries with large demands for hydrogen could have their own hydrogen storage, such that they could adjust their production patterns in a way that is different from that implied by the results of this work (i.e., this work does not link hydrogen storage to any specific industry).

Considering the selection of included industries, it is acknowledged that also other industries and applications for direct and indirect electrification (*via* hydrogen) could have been included. The aim of the study is, however, not to model all industries that potentially could be electrified (with or without hydrogen), but to investigate the dynamics in hydrogen supply cost. In the steel industry, several companies have already decleared their interest in a hydrogen based process (ArcelorMittal S.A. [33], Vostalpine AG [34], HYBRIT [22]), and production of ammonia is already based on hydrogen, although with fossil origin, and thus a shift to renewable hydrogen is a highly plausible option to reduce emissions.

Considering the cement industry, which is an industry with considerable CO_2 emissions, an electrified process would generat a clean CO_2 stream (since the process has inherent CO_2 emission) that would be relatively easy to capture and store, compared to if the process had not been electrified. In addition, hydrogen is included in the transport sector and to balance variations in the electricity sector itself, and thus it can be argued that a significant share of potential future direct and indirect (hydrogen) electrification applications is included in this work. However, it is of course not certain that these sectors will develop according to our assumptions, nor is it certain that the same quantities of the industrial commodities will be required in the future. Furtermore, also other sectors could be electrified, e.g., synthetic fuels for aviation and maritime transport, chemical processes, and non-ferrous metal metallurgy. Thus, future demand for electricity and hydrogen may be higher than what is assumed in this work.

Regarding the ‘traditional’ demand, which is assumed to remain at the current level for the coming decades, it is likely that some countries will reduce their traditional demands due to efficiency measures, whereas other countries will increase them, for instance through electrification of space heating in regions that currently use natural gas (and possibly solid fuels) as heating fuels. In the model, the traditional demand constitutes around 60 % of the total electricity demand in most of the countries. Therefore, the results would not be substantially different if the traditional demand changed slightly.

The competitiveness of hydrogen production from SMR-CCS is clearly affected by the cost of natural gas, which in this work is assumed to be 28 €/MWh (including a fraction of biogas). This cost is in line with the natural gas cost during the first half of Year 2021 [35], and as-concluded in this work, the competitiveness of hydrogen production from SMR-CCS is limited. Considering then the evolution of the cost of natural gas at the end of Year 2021 and beginning of Year 2022, with costs consistently above 80 €/MWh and with peaks above 200 €/MWh [35], the use of SMR-CCS would appear to be even less-competitive. For some industries, however, having the security of a continuous supply may be more important than the cost, and the use of SMR-CCS may be an additional option if the electricity system cannot supply enough renewable electricity or if the local distribution grid limits the supply. Thus, hydrogen from SMR-CCS, so-called blue hydrogen, could acts as a bridging solution during the initial phase of the expected energy system transitioning.

5. Conclusion

An energy systems model is applied to evaluate how the cost of hydrogen production varies over time and to identify how different parameters influence the hydrogen cost. A zero-carbon emissions energy system is modeled that includes both the traditional electricity demand and the potential future electricity demands from transport and industry, covering four European regions with different potentials for VRE.

As expected, the results show that hydrogen produced through electrolysis in systems with high shares of VRE vary significantly in terms of both annual and hour-to-hour costs. Thus, the main parameter that affects the cost of hydrogen is the cost of electricity. However, this work indicates that, in addition, the actual dimensioning of the cost-optimal electrolyzer and hydrogen storage capacity can have significant impacts on the cost of hydrogen during different periods of the year, i.e., the relationship between electrolyzer and hydrogen storage capacity can be the factor that determines the marginal price for the hydrogen production system, and thus, is highly dependent upon the system composition. Furthermore, the results show that the characteristics of the hydrogen demand can have a strong impact on the hydrogen cost, where flexibility in hydrogen-based industries can reduce the cost of hydrogen by up to 35 %, as compared to a constant hydrogen demand.

It can also be concluded that time-shifting of electricity generation through hydrogen production and subsequent reconversion back to electricity plays an important role in the climate-neutral electricity system investigated, decreasing the average electricity cost by 2 %–16 %. The two technologies included for the reconversion of hydrogen back to electricity are fuel cells and hydrogen-fueled gas turbines. Under the assumptions applied in this work, only gas turbines attain investments.

Finally, the cost of supplying hydrogen from a system operated in off-grid, island-mode is concluded to be always more expensive than that from a fully interconnected energy system, even when the off-grid system may use the best wind and solar PV sites available.

CRediT authorship contribution statement

Simon Öberg: Conceptualization, Methodology, Visualization, Writing – original draft. **Mikael Odenberger:** Methodology, Supervision, Writing – review & editing. **Filip Johnsson:** Supervision, Writing – review & editing.

Declaration of Competing Interest

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

Data availability

Data will be made available on request.

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Appendix A

The implementation of the industrial demands for hydrogen and electricity is described by Equations (A.2)–(A.9), and the objective function is described by Equation (A.1). Sets, variables, and parameters are defined and explained in Table A.1.

The objective function, shown in Equation (A.1), minimizes the total system cost and includes annualized capital costs, fixed and variable operational costs (where fuel costs are included in C_p^{OPEX}), and costs related to part-load operation and start-ups, as well as the cost for transmission of electricity.

$$\min\sum_{r\in R}\left(\sum_{p\in P} i_{r,p}*C_p^{inv}+\sum_{p\in P}(i_{r,p}+E_{r,p})*C_p^{fixOM}+\sum_{t,p\in T,P^{gen}} g_{r,t,p}*C_p^{OPEX}+\sum_{t,p\in T,P^{gen}}\left(g_{r,t,p}^{active}-g_{r,t,p}\right)*C_p^{part}+\sum_{t,p\in T,P^{gen}} g_{r,t,p}^{start}*C_p^{start}+\sum_{r',b\in R,B} i_{r,r',b}^{tran}*C_{b,r,r'}^{trans}\right) \tag{A1}$$

The production of commodity i at time-step t in region r is included in the global electricity and hydrogen balance, as shown in Equations (A.2) and (A.3), respectively.

$$\begin{aligned} &D_{r,t}^{elec}+D_{r,t}^{BEV}+\sum_{r',p\in R,P^{tran}} x_{r,r',t}^{netexport}+g_{r,t,electrolyser}\\ &+s_{r,t,p}^{charge}\bullet\left(1-\eta_{H2comp}\right)+\sum_{i\in I} g_{i,t,r}^{ind}\bullet\theta_i^{el}\\ &\leq\sum_{p\in P^{gen}} g_{r,t,p}+\sum_{p\in P^{storage}}\left(s_{r,t,p}^{discharge}-s_{r,t,p}^{charge}\right)\forall t,r\in T,R \end{aligned} \tag{A2}$$

Table A1
Sets, variables, and parameters used in the mathematical description of the industrial demands added to the model.

Sets		
R	Regions, {1,..,r}	
T	Time-step, {1,..,8760}	
I	Industries (steel, cement, ammonia)	
P	Technology	
P^{gen}	Electricity-generating technologies	
P^{trans}	Transmission technologies (OHAC and HVDC)	
$P^{storage}$	Energy storage technologies (Li-ion battery, hydrogen storage)	
P^{H2}	Hydrogen production technologies	
Variables		
$i_{r,p}$	Investment in technology p in region r	[GW]
$g_{r,t,p}$	Generation, or storage level, for technology p at time-step t in region r	[GWh/h]
$g_{i,t,r}^{ind}$	Generation of industry commodity i at time-step t in region r	[tonne/h]
$x_{r,r',t}^{netexport}$	Electricity net export from region r to region r' during time-step t	[GWh/h]
$s_{r,t,p}^{charge}$	Charging of storage p in region r at time-step t	[GWh/h]
$s_{r,t,p}^{discharge}$	Discharging of storage p in region r at time-step t	[GWh/h]
Parameters		
C_p^{inv}	Investment cost for technology p	[k€/GW]
C_p^{OPEX}	Running cost (fuel, CO_2 and variable O&M cost) for technology p	[k€/GWh]
C_p^{fixOM}	Fixed yearly O&M cost for technology p	[k€/GW]
C_p^{start}	Start-up cost for technology p	[k€/GW]
C_p^{part}	Part-load cost for technology p	[k€/GW]
$E_{r,p}$	Existing capacity of technology p (from real-world databases or from previous investment periods) in region r	[GW(h)]
$D_{i,r}^{ind}$	Demand for industrial commodity i in region r	[GWh]
$D_{t,r}^{elec}$	Traditional electricity demand at time-step t in region r	[GWh]
$D_{r,t}^{BEV}$	Electricity demand in BEV fleet during hour t in region r	[GWh]
ξ_i^{up}	Upper production capacity for industry i	[-]
ξ_i^{low}	Lower production capacity for industry i	[-]
γ_i	Change in production rate per hour for industry i	[% / h]
η_{H2comp}	Energy loss due to compression of hydrogen	[-]
θ_i^{el}	Electricity demand per tonne of industrial commodity i	[GWh]
θ_i^{H2}	Hydrogen demand per tonne of industrial commodity i	[GWh]

$$\sum_{t,p\in T,P^{H2}} g_{r,t,p} \geq \sum_{t,i\in T,I} g^{ind}_{i,t,r} \bullet \theta^{H2}_i + \sum_{t\in T} g_{r,t,FuelCell} \bullet \frac{1}{\eta_{FuelCell}}$$

$$+\sum_{t\in T} g_{r,t,H2GT} \bullet \frac{1}{\eta_{H2GT}} \forall r \in \mathrm{R} \quad \text{(A3)}$$

Equation (A.4) ensures that the assigned amount of commodity i is generated in region r.

$$\sum_{t\in T} g^{ind}_{i,t,r} \geq D^{ind}_{i,r} \forall i, r \in \mathrm{I}, \mathrm{R} \quad \text{(A4)}$$

When there is no flexibility in the industrial process, the production of commodity i at time-step t in region r, $g_{i,t,r}$, is constant, and is calculated according to Equation (A.5). When flexibility is allowed in the industries, Equations (A.6) and (A.7) limit the upper and lower production levels of commodity i at time-step t for all regions in R, respectively.

$$g^{ind}_{i,t,r} = D^{ind}_{i,r} \bullet \frac{1}{8760} \forall i, t, r \in \mathrm{I}, \mathrm{T}, \mathrm{R} \quad \text{(A5)}$$

$$g^{ind}_{i,t,r} \leq D^{ind}_{i,r} \bullet \frac{1}{8760} \bullet \xi^{up}_i \forall i, t, r \in \mathrm{I}, \mathrm{T}, \mathrm{R} \quad \text{(A6)}$$

$$g^{ind}_{i,t,r} \geq D^{ind}_{i,r} \bullet \frac{1}{8760} \bullet \xi^{low}_i \forall i, t, r \in \mathrm{I}, \mathrm{T}, \mathrm{R} \quad \text{(A7)}$$

Equations (A.8) and (A.9) limit how rapidly the production of commodity i changes from one time-step to the next.

$$g^{ind}_{i,t,r} \geq g^{ind}_{i,t-1,r} \bullet (1-\gamma_i) \forall i, t, r \in \mathrm{I}, \mathrm{T}, \mathrm{R} \quad \text{(A8)}$$

$$g^{ind}_{i,t,r} \leq g^{ind}_{i,t-1,r} \bullet (1+\gamma_i) \forall i, t, r \in \mathrm{I}, \mathrm{T}, \mathrm{R} \quad \text{(A9)}$$

Appendix B

See Table B1.

Table B1
Traditional electricity demands and production levels of crude steel, ammonia and cement in the regions included in the modeling.

Region	Traditional electricity demand [TWh]	Production of steel [kt/a]	Production of ammonia[a] [kt/a]	Production of cement [kt/a]
AT	67.3	7,570	485	5,520
BE	86.9	5,000	1 020	6,520
CH	61.8	–	–	3,800
CZ	63.3	2,400	350	5,000
DE1	179.2	–	1 116	10,500
DE2	30.4	6,000	189	950
DE3	205.5	16,760	1 279	15,970
DE4	108.1	2,400	673	7,560
DE5	28.9	3,800	180	–
DK1	16.4	–	–	–
DK2	17.5	–	–	2,100
ES1	23.9	5,400	55	4,300
ES2	125.8	–	288	20,530
ES3	73.6	–	168	10,910
ES4	42.7	–	98	8,830
FI	84.2	2,600	–	1,550
FR1	53.1	5,100	164	4,100
FR2	46.4	–	142	–
FR3	56.8	–	175	4,680
FR4	35.2	–	108	3,110
FR5	293.9	6,750	905	11,950
IE	28.3	–	–	6,300
IT1	174.9	–	329	16,430
IT2	76.6	–	144	12,240
IT3	67.1	11,500	126	15,640
LU	6.5	–	–	1,000
NL	116.4	7,500	2 716	1,800
NO1	108.5	–	422	1,200
NO2	9.7	–	38	–
NO3	10.2	–	40	1,200
PO1	47.0	7,600	996	10,600
PO2	61.2	–	1 297	5,900
PO3	43.3	–	917	2,000
PT	52.5	–	–	11,580

(continued on next page)

Table B1 (*continued*)

Region	Traditional electricity demand [TWh]	Production of steel [kt/a]	Production of ammonia[a] [kt/a]	Production of cement [kt/a]
SE1	26.3	–	–	–
SE2	86.1	1,700	–	3,400
SE3	18.2	–	–	–
SE4	7.0	2,200	–	–
UK1	305.9	8,100	985	8,650
UK2	28.1	–	90	1,000
UK3	7.8	–	25	1,000

[a] As production capacity data are only available per country, the regional production capacity has been calculated by scaling the total production capacity according to the gross domestic product distribution for the regions (for countries constituted by more than one NUTS2 regions).

Appendix C

The assumed number of vehicles in the Year 2050 are displayed for the different regions in Table C.1, and in addition the yearly driving ranges are 13,000, 14,000, 41,000, and 57,000 km per year for electric vehicles, light trucks, busses, and heavy trucks, respectively. The corresponding electricity consumption per km used is 0.16, 0.33, 1.19, and 2.06 kWh. This input data is taken from the work by Taljegård et al. [18].

Table C1
Number of vehicles assumed in each category (electric vehicle (EV), light truck (LT), heavy truck (HT), and bus) and region by 2050 in thousands of vehicles.

Region	EV	LT	HT	Bus	Region	EV	LT	HT	Bus
AT	5,841	357	51	7	IE	2,534	285	19	8
BE	6,918	N/A	N/A	12	IT1	25,292	1,755	334	40
CH	5,484	325	41	6	IT2	11,076	768	146	17
CZ	6,292	405	217	15	IT3	9,706	673	128	15
DE1	18,202	657	175	19	LU	468	N/A	5	1
DE2	3,088	111	30	3	NL	9,956	789	64	7
DE3	20,875	753	200	22	NO1	2,164	369	63	10
DE4	10,984	396	105	11	NO2	194	33	6	1
DE5	2,944	106	28	3	NO3	203	34	6	1
DK1	1,437	181	14	5	PO1	7,908	723	198	26
DK2	1,536	193	15	5	PO2	10,304	943	257	33
ES1	2,478	388	29	4	PO3	7,282	666	182	24
ES2	13,004	2,037	154	21	PT	5,839	1,200	51	11
ES3	7,606	1,191	90	12	SE1	714	57	10	1
ES4	4,412	691	52	7	SE2	4,350	346	61	8
FI	3,979	394	138	13	SE3	206	16	3	0.4
FR1	4,350	652	36	8	SE4	295	23	4	0.5
FR2	3,799	570	32	7	UK1	33,308	3,095	316	109
FR3	4,655	698	39	8	UK2	3,055	283	29	10
FR4	2,880	432	24	5	UK3	850	79	8	3
FR5	24,081	3,612	200	45					

Appendix D

The resulting investments for the off-grid scenarios modeled are listed in Table D.1. Both wind power and solar PV are installed in all scenarios and regions, which emphasizes that these two technologies can complement each other. The value of batteries is apparent primarily in regions with favorable solar resources throughout the year (ES4), and the value of hydrogen storage diminishes with increased flexibility of the industrial process. With high flexibility in ES4, the model identifies the optimal solution without investing in hydrogen storage capacity.

Table D1
Installed capacities for the three island scenarios (Scenarios 8a–c) in four different regions.

Region	Industry flexibility scenario	Wind power [GW]	Solar PV [GW]	H_2-fueled gas turbine [GW]	Electrolyzer [GW]	Battery [GWh]	H_2 storage [GWh]
UK1	*NoFlex*	0.91	0.81	–	0.71	0.04	101
	LowFlex	0.94	0.57	–	0.71	–	40
	HighFlex	1.0	0.25	–	0.72	–	8.4
ES4	*NoFlex*	0.76	1.33	–	0.68	1.95	76
	LowFlex	0.40	1.37	–	0.61	3.8	20
	HighFlex	0.57	1.10	–	0.66	2.35	–
SE4	*NoFlex*	1.05	0.81	–	0.79	0.03	56
	LowFlex	0.99	0.74	–	0.74	–	24
	HighFlex	0.95	0.82	–	0.71	0.20	3.7
DE4	*NoFlex*	0.94	0.83	–	0.72	0.05	132
	LowFlex	0.88	0.85	–	0.71	0.30	39
	HighFlex	0.92	0.66	–	0.72	0.1	9.1

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