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Low-cost hydrogen in the future European electricity system – Enabled by flexibility in time and space

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HIGHLIGHTS

- Three types of hydrogen flexibility are assessed.
- The origin of electricity for hydrogen production of up to 2,500 TWh_{H2} is studied.
- Temporal flexibility enables increased integration of solar power.
- Hydrogen storage and flexibility in localization enhance expansion of wind power.

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ABSTRACT

The present study investigates four factors that govern the ability to supply hydrogen at a low cost in Europe: the scale of the hydrogen demand; the possibility to invest in large-scale hydrogen storage; process flexibility in hydrogen-consuming industries; and the geographical areas in which hydrogen demand arises. The influence of the hydrogen demand on the future European zero-emission electricity system is investigated by applying the cost-minimising electricity system investment model eNODE to hydrogen demand levels in the range of 0–2,500 TWh_{H2}. It is found that the majority of the future European hydrogen demand can be cost-effectively satisfied with VRE, assuming that the expansion of wind and solar power is not hindered by a lack of social acceptance, at a cost of around 60–70 EUR/MWh_{H2} (2.0–2.3 EUR/kg_{H2}). The cost of hydrogen in Europe can be reduced by around 10 EUR/MWh_{H2} if the hydrogen consumption is positioned strategically in regions with good conditions for wind and solar power and a low electricity demand. The cost savings potential that can be obtained from full temporal flexibility of hydrogen consumption is 3-fold higher than that linked to strategic localisation of the hydrogen consumption. The cost of hydrogen per kg increases, and the value of flexibility diminishes, as the size of the hydrogen demand increases relative to the traditional demand for electricity and the available VRE resources. Low-cost hydrogen is, thus, achieved by implementing efficiency and flexibility measures for hydrogen consumers, as well as increasing acceptance of VRE.

1. Introduction

The demand for hydrogen is expected to increase dramatically within Europe in the coming decades as efforts intensify to meet climate targets [1]. Hydrogen may play a crucial role in the elimination of carbon dioxide emissions in the industry and transport sectors. Hydrogen can be deployed as an energy carrier, reducing agent and raw material, as emphasised by the European Commission in the official document: "*A hydrogen strategy for a climate-neutral Europe*" [2]. As an energy carrier, hydrogen offers: i) a high gravimetric energy density relative to batteries; and ii) the possibility for storage on a large scale. The former makes hydrogen attractive as an energy carrier in long-distance transport, such as heavy trucks, and potentially in shipping, while the latter implies that hydrogen can support the balancing of supply and demand in electricity systems with a high share of variable renewable electricity (VRE). As a reducing agent, hydrogen can replace coal in industrial processes, forming water instead of carbon dioxide when reacting with oxygen. Hydrogen is, for example, proposed as an agent to reduce iron ore to iron in green steel production [3]. As a raw material, hydrogen in combination with biogenic or air captured carbon can be used to generate electrofuels for aviation [4] or olefins for the production of materials [5]. Hydrogen is also central to the production of ammonia, which is a

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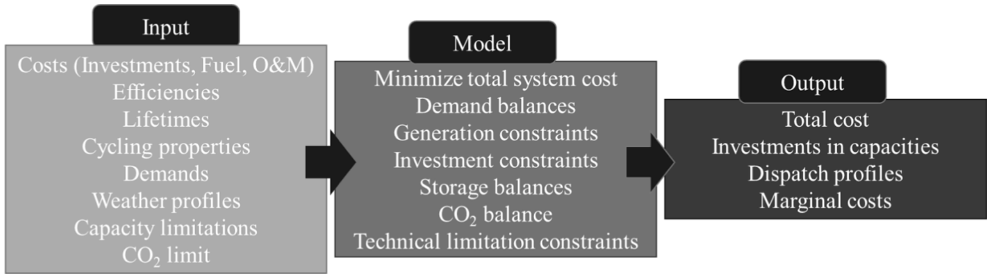

Fig. 1. Simple overview of the eNODE model.

key component of fertilisers [6]. The importance of hydrogen for achieving decarbonisation varies between sectors and applications. Hydrogen is of great importance for industries such as steel manufacturing that currently entail high levels of carbon dioxide emissions and for which there are few available mitigation options. Consequently, there are several ongoing projects related to hydrogen deployment in such industries [7–9]. The role of hydrogen is perhaps less critical in those sectors in which there exist competitive options, e.g., road transportation, where hydrogen use as an energy carrier has strong competition from the use of electric vehicles with batteries. However, it is clear that hydrogen can enable reductions in emissions from different parts of the energy system, even though the magnitude of the future demand for hydrogen is uncertain [1,10,11].

At present, hydrogen is primarily produced from natural gas and this process is associated with carbon dioxide emissions [12]. An alternative to fossil-based hydrogen is hydrogen that is produced through the electrolysis of water using carbon–neutral electricity. The new demand for electricity to produce hydrogen may, if it becomes sufficiently large, have significant implications for the electricity system. The distribution of the hydrogen demand in time and the localisation of the hydrogen demand could have consequences for decisions related to which electricity generation technologies attract investments. The distribution of the hydrogen demand in time and space depends on the application. Previous work has shown that energy-intensive processes, such as hydrogen-fed steel manufacturing, may be localised in proximity to a resource, e.g., iron ore, or localised in areas with renewable electricity sources that produce electricity at low cost [13].

In a previous electricity system modelling study conducted by Johansson and Göransson (2020), it was shown that by over-investing in electrolysis capacity and hydrogen storage, the production of hydrogen could be allocated to periods with medium-to-high availability levels of wind and solar power, which would facilitate further integration of wind and solar power, as compared to nuclear- or bio-fuelled generation [14]. This issue was further addressed in the work of Öberg et al. (2022) [15], who concluded that a heavy demand for hydrogen reduces the demand for peak power, e.g., from gas turbines. This is because a large electrolyser capacity can act as “inverted peak power”, reducing electricity consumption by reducing hydrogen production, during periods with high electricity prices, instead of starting-up technologies to compensate for the reduced production from VRE technologies. However, a prerequisite for this is the availability of hydrogen storage units that enable the industry to maintain its operation during periods when the electrolyser is not producing hydrogen.

Obviously, the ability of a hydrogen demand to facilitate the integration of wind and solar power will rely on available wind and solar resources that cannot be utilised cost-efficiently without the flexibility properties of hydrogen. Four main factors influence the ability of VRE to supply hydrogen to a low cost in Europe: (i) the scale of the hydrogen demand; (ii) the possibility to invest in large-scale hydrogen storage; (iii) process flexibility in hydrogen-consuming industries; and (iv) the geographical areas in which the hydrogen demand may arise. Lux and Pfluger (2020) [16] have investigated the relationship between the hydrogen demand and the cost of hydrogen in the European electricity system, and found that meeting the future demand for hydrogen with wind and solar power is likely to result in hydrogen prices above 100 EUR/MWh_{H2}.

It is important to increase knowledge regarding how the energy and electricity systems of Europe may change given different levels of hydrogen demand. In particular, it is interesting to understand which power supply options are connected to different levels of hydrogen demand and in which geographical areas hydrogen production can be concentrated. The present study investigates the origin of the electricity for hydrogen production, assuming that hydrogen is produced through electrolysis. Furthermore, the present study investigates the relationship between the size of the hydrogen demand and the value of the flexibility that hydrogen production contributes to the electricity system. The aim of this work is to increase understanding of how the source and cost of hydrogen depend on the size of the hydrogen economy and the impact that a hydrogen demand has on other electricity consumers. This work builds on and expands the analysis of Lux and Pfluger (2020) [16]. Their work assumed an all-renewable electricity system with a fixed limit on wind and solar power site availability. In this work, a larger set of electricity generation technology options is available, including nuclear power and biogas-fuelled power plants. The number of sites available for wind and solar power installations is varied, to reflect different levels of social acceptance. In addition, the impact of the inherent flexibility of a hydrogen demand on the electricity system is assessed. Three types of flexibility are investigated: (i) flexible hydrogen production through over-dimensioning of the electrolyser and investments in hydrogen storage; (ii) flexible hydrogen consumption (which offers flexible hydrogen production without storage investments); and (iii) flexibility with respect to the localisation of hydrogen consumption. This work add to previous work by showing how the value of flexibility changes with an increasing demand for hydrogen.

2. Method

The impact of hydrogen production on the European electricity system is investigated by applying the cost-minimising electricity system investment model eNODE to six cases. The cases differ in terms of the allocation of hydrogen demand both geographically and in time, as well as in terms of the availability of hydrogen storage and electricity generation options. In addition, each case is investigated for six different level of hydrogen demand, resulting in 36 model runs.

2.1. eNODE -Electricity system investment model

The electricity system model applied in the present work, which has also been used in previous publications by the authors, is termed the ‘eNODE model’. The eNODE model minimises the costs for investments in and operation of an electricity system, while meeting exogenously given demands for electricity and hydrogen in a future European context, assuming zero emissions of carbon dioxide. The eNODE model was originally formulated by Göransson et al. (2017) [17] and further developed by Taljegard et al. (2019) [18], Johansson and Göransson (2020) [14] and Walter and Göransson (2022) [19]. A simple overview

Table 1
Overview of the six cases.

	H_2 storage	Flexible H_2 demand	Geographical distribution of H_2 demand	Nuclear power	VRE availability
Ref	Yes	No	Fixed	Yes	100 %
No storage	No	No	Fixed	Yes	100 %
Time	Yes	Yes	Fixed	Yes	100 %
Location	Yes	No	Optimised	Yes	100 %
No Nuc	Yes	No	Fixed	No	100 %
Low VRE	Yes	No	Fixed	Yes	50 %

of the eNODE model is seen in Fig. 1 and a full mathematical description of the model is given in Appendix A.

In this study, the eNODE model covers the geographical scope of Europe, represented by 22 regions and including possibilities for trade between the regions. The geographical scope corresponds to the area of the EU (excluding Cyprus and Malta), Great Britain, Norway, and Switzerland, subdivided into 22 regions based on the main transmission grid bottlenecks. A map of the modelled regions is given in Appendix C. The model applies 730 consecutive time-steps, which vary in length from 5 to 19 h and represent a single future year. The time-steps, created in accordance with the method developed by Pineda and Morales (2018) [20], are designed to capture load, wind, and solar power profiles. The goal of the present study is to assess the impacts of flexible, electrolysis-driven hydrogen production on cost-optimal electricity systems, in terms of both composition and operational parameters. It is considered of importance that the model takes into account both variability and different strategies that can manage variations in power generation and electricity demand, such as stationary batteries, transmission lines and hydrogen storage. Electricity generation and storage technologies that are available for investments and their properties are listed in Appendix B.

The onshore wind farm, offshore wind farm and solar PV park power densities are set at 5 MW/km^2, 8 MW/km^2 and 45 MWp/km^2, respectively. Thus, the potential levels of employment of wind power and PV are be limited by the amount of space that is available, which is calculated for suitable land areas or by deducting unsuitable land areas from the total available areas of the studied regions, using the tool of Mattsson et al. (2021) [21]. Land areas that are unsuitable in relation to onshore wind include protected areas, lakes and streams, and urban areas. For solar PV, protected areas, lakes and streams, forests and croplands are assumed to be unsuitable. For offshore wind, the assumptions applied to suitable areas are: minimum distance of 2 km to the shore; non-protected areas; and maximum water-depth of 50 m. In addition, the space available is assumed to be limited to 8 %, 10 % and 10 % of the land area suitable for onshore wind, offshore wind, and solar power, respectively. This means that maximum potential capacities for onshore wind, offshore wind, and solar power in the modelled regions are 1.3, 0.23 and 4.4 TW, respectively. This corresponds to maximum annual generation levels of 3,000, 1,000 and 6,400 TWh, respectively, when applying the capacity factors from the supply curves. For the maximum capacities on a regional basis, as well as the potential full-load hours, see Table 5 and Table 6 in Appendix B.

Hydropower capacity, transmission grid capacity, and new nuclear power capacity are assumed to be in place for the future year investigated. For other technologies the model is a greenfield one, i.e., one in which new investments need to be made. The time-frame for the study is not explicitly stated, although the costs for electricity generation and storage technologies are set to represent Year 2050 levels and no investments in electricity generation technologies associated with fossil carbon dioxide emissions are allowed.

The electricity demand in the regions investigated includes the current electricity demand, as well as full electrification of the passenger car fleet and partial (60 %) electrification of the heavy-duty vehicle fleet [18]. In addition, for Germany and the UK, also included in the model is an electricity demand that includes the electricity required to replace natural gas-based heating for decentralised heat pumps [22]. The total electricity demand per region can be found in Table 7 in Appendix D. For the countries investigated, the total electricity demand is 4,640 TWh/year without hydrogen production.

Due to the large uncertainty associated with the future demand for hydrogen produced through electrolysis, the hydrogen demand is varied in the model, from 0 TWh_{H2} to 2,500 TWh_{H2} in steps of 500 TWh_{H2}. The levels of hydrogen demand investigated in this study are similar to the scenarios described in the European Hydrogen roadmap and span from their business-as-usual scenario for Year 2030 to their ambitious scenario for Year 2050 [1]. Hydrogen is, in this study, assumed to be produced by electrolysis with an efficiency of 70 % at a cost of 400 EUR/kW and with a lifetime of 20 years. In terms of the electricity needed to produce the indicated amounts of hydrogen, this adds just over 700 TWh to each step and almost 3,600 TWh for the highest hydrogen demand level. The six levels of hydrogen demand are, in all the investigated cases but one, assumed to be continuous over time, which may seem like a crude assumption, but it is motivated by the fact that a large fraction of the produced hydrogen is expected to be used in industrial processes, which traditionally have been operated around the clock.

2.2. Cases

The impact of hydrogen production on the European electricity system is investigated for six cases, see Table 1. First, a reference case (*Ref*) is modelled, which is used in the comparisons with five additional cases that are constructed to address: (i) the impact of not having the flexibility of hydrogen storage (*No storage*); (ii) the flexibility of hydrogen demand in time (*Time*); and (iii) the flexibility of hydrogen demand in terms of location (*Location*); iv) a limited acceptance of nuclear power (*No nuc*); and v) a low level of acceptance of VRE (*Low VRE*). Electrolysis is assumed to be the only means of producing hydrogen in all the modelled cases, and it is assumed that it is not possible to trade hydrogen between the regions.

2.2.1. Ref

In the *Ref* case, the hydrogen demand is assumed to be constant over time and either met directly by electrolysis or by discharging stored hydrogen. In this case, the European hydrogen demand is geographically allocated to each region in proportion to the historical yearly electricity demand (see Table 8 in Appendix E).

2.2.2. No storage

The *No storage* case applies the same assumptions as the *Ref* case except that the hydrogen demand is met directly by electrolysis without any possibility to use hydrogen storage. This case evaluates the benefit of hydrogen storage when the results are compared with the *Ref* case.

2.2.3. Time

The *Time* case offers increased temporal flexibility of the hydrogen demand, as compared to the *Ref* case. The regional demand for hydrogen, which is the same as the *Ref* case, is required to be met on an annual basis rather than on an hourly basis. Thus, the *Time* case eliminates the need for hydrogen storage, as the consumption of hydrogen can closely follow its production.

2.2.4. Location

In the *Location* case, the geographical localisation of the hydrogen demand is flexible compared to the *Ref* case. However, regardless of where the hydrogen demand is located, it is assumed to be constant in time. The *Location* case represents a situation in which the model can make use of low-cost electricity in all regions and can assign the location of hydrogen-intensive industries based on the availability of low-cost electricity.

2.2.5. No nuc

The *No nuc* case applies the same assumptions as the *Ref* case, albeit without any nuclear power, (i.e., neither new investments nor already existing plants are permitted).

2.2.6. Low VRE

The *Low VRE* case applies the same assumptions as the *Ref* case but with a reduced socio-technical potential for VRE, i.e., wind power (both on– and offshore) and solar PV. The upper limits on VRE investments (in terms of MW/km^2) are assumed to be 50 % of the levels in the *Ref* case, such that all regions and technologies represent limited acceptance of wind and solar power expansion.

2.2.7. Additional cases -low cost of hydrogen storages

In addition, the *Ref* case and *Location* case were run with reduced hydrogen storage cost to represent the cost of salt caverns (1.1 EUR/kWh compared to 11 EUR/kWh).

3. Results

Fig. 1 shows how an increasing hydrogen demand is met by the electricity supply-side. The total electricity supply for different hydrogen consumption levels is shown in Fig. 1a, and the additional hydrogen demand covered by different electricity generation technologies (as compared to the previous demand level) is shown in Fig. 1b. The cost-efficient combination of electricity generation technologies to meet the demand for hydrogen depends on the flexibility of the hydrogen demand, as well as the assumptions made regarding the availability of renewable energy sources and nuclear power, as shown in Fig. 2. In the *Ref* case, VRE supplies the vast majority of the electricity demand for hydrogen production (>88 %) until the demand reaches 500 TWh$_{H2}$. For demand levels > 500 TWh$_{H2}$, VRE still accounts for the majority of the electricity supply in the *Ref* case (Fig. 1a), although new nuclear power provides a substantial share (29 %–45 %) of the electricity generation that must be added to meet the additional hydrogen demand (Fig. 1b). With a hydrogen demand that is flexible in relation to geography (*Location* case) or time (*Time* case), at least 90 % of the electricity used to produce hydrogen is supplied by VRE for hydrogen demands up to 2000 TWh$_{H2}$.

The ratio of wind power to solar power varies between the cases, whereby there is a particular emphasis on solar power in the *Time* case with a hydrogen demand that is flexible in time. Temporal flexibility stimulates investments in solar PV because it provides the possibility to reduce hydrogen production during the dark winter months. Hydrogen consumption that is flexible in time also reduces the need for biogas peak- and mid-merit electricity generation, as shown in Fig. 1b, and the hydrogen can be produced almost completely from VRE. With free localisation of hydrogen demand, the good wind resources in the regions with historically low electricity demand in the northern part of Europe, as well as the good solar resources in the southern part of Europe are best put to use (compare Table 9 to Table 8 in Appendix E).

The supply-side is also dominated by VRE in the case without nuclear power (*No Nuc* case), while nuclear power supplies most of the electricity for hydrogen production in the case where VRE expansion is more-strictly limited (*Low VRE* case). The *No Nuc* case shows the heaviest dependence on biogas among the cases investigated, whereas it is the case that is the least reliant on dispatchable generation. If hydrogen cannot be stored (*No storage* case), wind power production is reduced, as compared to the *Ref* case, and replaced by nuclear power.

In comparison to the other cases, the level of VRE in the *Low VRE* case may be perceived as low. However, even in this case there is a 10-fold increase in solar power, a tripling of onshore wind power, and a quadrupling of offshore wind power capacity to meet a 2,500 TWh$_{H2}$ hydrogen demand, compared to the cumulative installed capacities in Year 2020.

The results show that the cost of hydrogen increases with the increase in hydrogen demand for all six cases. Fig. 3 gives the average annual cost of hydrogen, calculated as the difference between the total system cost for the considered hydrogen demand level and that for the previous hydrogen demand level, divided by the difference in hydrogen demand. (The same graph including the additional cases with reduced cost for hydrogen storage is seen in Fig. 7.) The average cost of hydrogen in the *Ref* case ranges from 57 EUR/MWh$_{H2}$ at 500 TWh$_{H2}$ of demand to 71 EUR/MWh$_{H2}$ at 2,500 TWh$_{H2}$ of demand, which corresponds to an average cost in the range of 1.9–2.4 EUR/kg$_{H2}$. When there is a low demand for hydrogen, there is a larger difference in the cost of hydrogen between the cases investigated, as compared to a situation with a higher

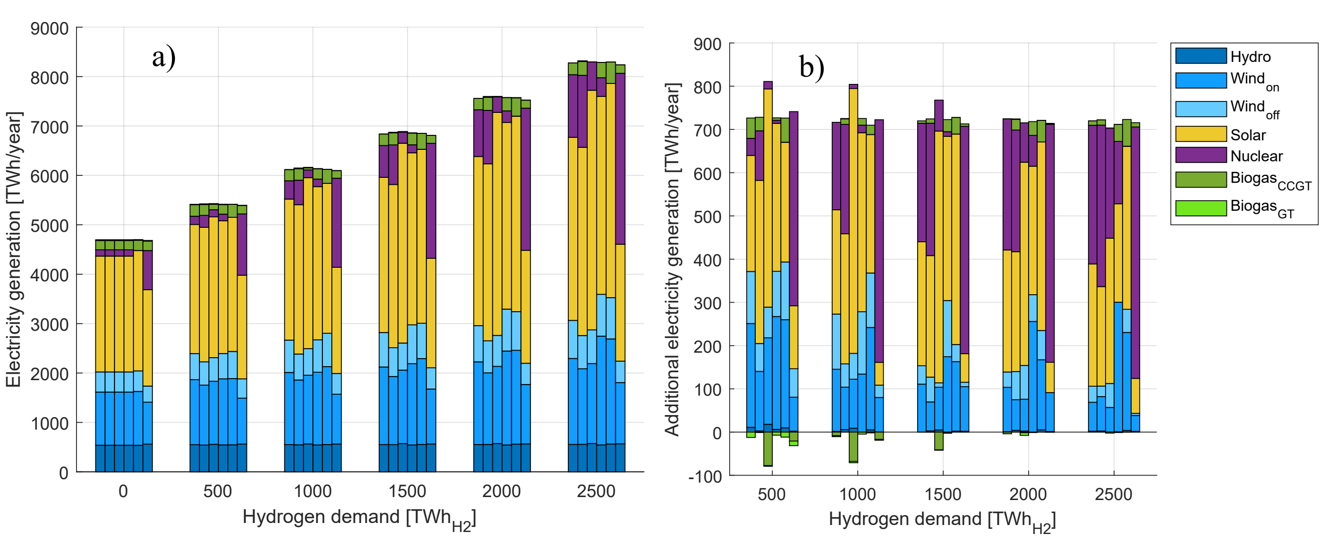

Fig. 2. a): Electricity mixes for the six modelled cases at the six hydrogen demand levels. b): Addition (and subtraction) of different electricity generation sources when increasing the demand of hydrogen, as compared to the previous demand level. Order of the data columns: Ref, No storage, Time, Location, No Nuc, Low VRE.

demand for hydrogen. The lowest cost for hydrogen, 22 EUR/MWh_{H2}, is seen for the case in which hydrogen production is flexible in time (*Time* case). The *No storage* case has the highest cost for hydrogen at low hydrogen demand (68 EUR/MWh_{H2} at 500 TWh_{H2}). However, the cost of hydrogen is close to constant in the *No storage* case, while it increases in line with the hydrogen demand in the other cases, resulting in more-similar hydrogen production costs in all the cases at 2,500 TWh_{H2}.

The maximum possible cost of hydrogen from the model is 82 EUR/MWh_{H2} (except in the *No Nuc* case), corresponding to investing exclusively in nuclear power and electrolysis, with both producing at full capacity in every hour. The cost of hydrogen is, however, less than 82 EUR/MWh_{H2}, even for the *Low VRE* case at 2,500 TWh_{H2}, since nuclear power reduces the need for transmission and batteries and because a share of the hydrogen still originates from VRE, which has a lower cost. In the *No Nuc* case, the increasing difficulty experienced with meeting the demands for electricity and hydrogen results in the most-expensive hydrogen at a demand of 2,500 TWh_{H2}.

Hydrogen production offers flexibility to the electricity system. The cases investigated include three types of flexibility: (i) flexible hydrogen production, achieved through over-dimensioning of the electrolyser and investments in hydrogen storage; (ii) flexible hydrogen consumption (which offers flexible hydrogen production without storage investments); and (iii) flexibility with respect to the localisation of hydrogen demand. In the *No storage* case, these flexibility options are not available. Thus, this case can be used as a reference to estimate the value of flexibility. In the *Ref* case, flexibility *via* hydrogen storage is available. At 500 TWh_{H2}, the cost of hydrogen in the *Ref* case is 10 EUR/MWh_{H2} lower than it is in the *No storage* case. However, at 1,500 TWh_{H2} and upwards the difference is very small, suggesting that the main benefit of hydrogen storage has been exhausted. In the *Location* case, flexibility is available through hydrogen storage and localisation of the hydrogen demand. At 500 TWh_{H2}, the cost of hydrogen is 10 EUR/MWh_{H2} lower for this case than for the *Ref* case, without flexible localisation of hydrogen consumption. The value of flexible localisation gradually declines as the level of hydrogen demand increases. At 2,500 TWh_{H2}, the value of flexible localisation of hydrogen production is down to 2 EUR/MWh_{H2}. In the *Time* case, with flexible hydrogen consumption, the cost of hydrogen is one-third of the cost of hydrogen in the *Ref* case, indicating that flexible hydrogen consumption is worth around 30 $EUR/MWh_{H2.}$ It should be noted that to achieve flexible hydrogen consumption and flexibility with regard to the localisation of hydrogen demand, investments and running costs outside the scope of this work are required.

A lower level of acceptance of nuclear power and VRE increases the cost of hydrogen (Fig. 2). The *No Nuc* case entails a relatively small additional cost for hydrogen when there is a low demand for hydrogen, as compared to the *Ref* case. The difference in hydrogen cost for the *No Nuc* case widens for each hydrogen demand level compared to the *Ref* case, as less-cost-effective wind and solar resources are traded to capacity-constrained regions where nuclear power would otherwise have been cost-effective and the hydrogen cost is>10 EUR/MWh_{H2} higher at 2,500 TWh_{H2}. The *Low VRE* case results in a cost for hydrogen that is 5–7 EUR/MWh_{H2} higher for all hydrogen demand levels, as compared to the *Ref* case.

The cost of hydrogen can be related to the origin of the electricity used for hydrogen production. As stated above, at low hydrogen production levels, the demand for hydrogen is mainly supplied by VRE for all cases, with the exception of the *Low VRE* case. The cost of VRE varies with location and time. This variation is exploited in the *Time* case and *Location* case, resulting in a low cost for hydrogen. The differences in the cost of hydrogen (Fig. 2) at low hydrogen demand levels highlight the benefits of allocating hydrogen consumption to sites where there are available resources for low-cost electricity and to hours of low net load, through very low-cost storage or flexible hydrogen consumption. When there is a high demand for hydrogen, this demand is met by nuclear power to a large extent in all cases. Since the cost of nuclear power is independent of time and location, there is a smaller difference in the cost of hydrogen for the cases investigated compared to the situation with low demand for hydrogen.

The change in total system cost as hydrogen demand is added is given in terms of its cost components in Appendix G for both the *Ref* case and the *Location* case. It is found that the cost of electrolysis and storage make up around one third of the cost at low hydrogen demand levels in both cases. The remaining two thirds correspond to costs for electricity generation, mainly from wind and solar power. At higher hydrogen demand levels, the cost share of the electrolyser and hydrogen storage is reduced to less than 20 % in the *Ref* case since a larger part of the hydrogen demand is met by nuclear power. In the *Location* case, the cost share of the electrolyser and hydrogen storage is less impacted since wind and solar power continues to play an important role in meeting the demand. However, at high hydrogen demand levels, biogas corresponds to almost 20 % of the cost in the *Location* case.

Fig. 3 gives the annual average electricity prices, here taken as the marginal costs for electricity, for the regions and cases investigated. The results indicate that the impact of hydrogen demand on the annual average electricity price varies significantly across regions and cases. In the *Location* case, there is a strong reduction of the electricity price difference between the regions as the demand for hydrogen increases. In this case, the demand for hydrogen is localised such that the VRE sites with the best conditions for wind and solar can be deployed. An analogy can be made to a situation in which industries move to regions that offer low-cost hydrogen and, thereby, gradually reduce the electricity price differences between regions. Furthermore, in the *Low VRE* case, the difference in average annual electricity price between regions is reduced as the hydrogen demand increases, since nuclear power, which is available at the same cost in all regions, is increasingly deployed to meet the hydrogen demand.

In the *No Nuc* case, the average annual electricity price increases with the hydrogen demand also in regions with a high initial electricity price. In this case, an increase in the hydrogen demand implies an increased reliance on biogas-fuelled generation as a dispatchable complement to VRE (biogas-fuelled generation is associated with a high running cost), an increased transmission network expansion, and increased utilisation of poor VRE resources. Both the *Time* case and *No Nuc* case result in larger differences in the annual average electricity price as the demand for hydrogen increases. In these cases, there are also large investments in transmission capacity (Fig. 5d).

Fig. 4 gives the investments made in hydrogen storage, electrolyser capacity, and stationary battery storage capacity, as well as the annualised cost of transmission investments. With over-investment in electrolyser capacity and hydrogen storage capacity, hydrogen can be distributed more freely in time to match the net load variability. On average, the European hydrogen storage systems are found to be most cost-efficient when sized so as to be filled in 2–3 days and emptied in 1–2 days, in all cases except in the *No storage* and *Time* cases.

With free localisation of the hydrogen demand (*Location* case), the investments in hydrogen storage and electrolyser capacity grow almost linearly as the demand for hydrogen increases. In this case (*Location* case), the hydrogen production is allocated to those regions that can meet the hydrogen demand at the lowest cost; these tend to be regions with available wind and solar resources that are best employed along with the usage of hydrogen storage. With a hydrogen demand that is flexible in time (*Time* case), there is no need for investments in hydrogen storage and the electrolyser capacity grows at an increasing rate as the demand for hydrogen increases. The high electrolyser capacity in the *Time* case makes it possible to match the hydrogen production to the wind and solar power production levels. The acceleration in electrolysis capacity for hydrogen demand levels $>$ 1,500 TWh_{H2} acts to increase the day-night flexibility handled directly by electrolysis (rather than using batteries) and this happens partly due to a reduction in the value of supplying electricity during nights with batteries as nuclear power is introduced. At medium to high levels of hydrogen demand (1,000–2,500

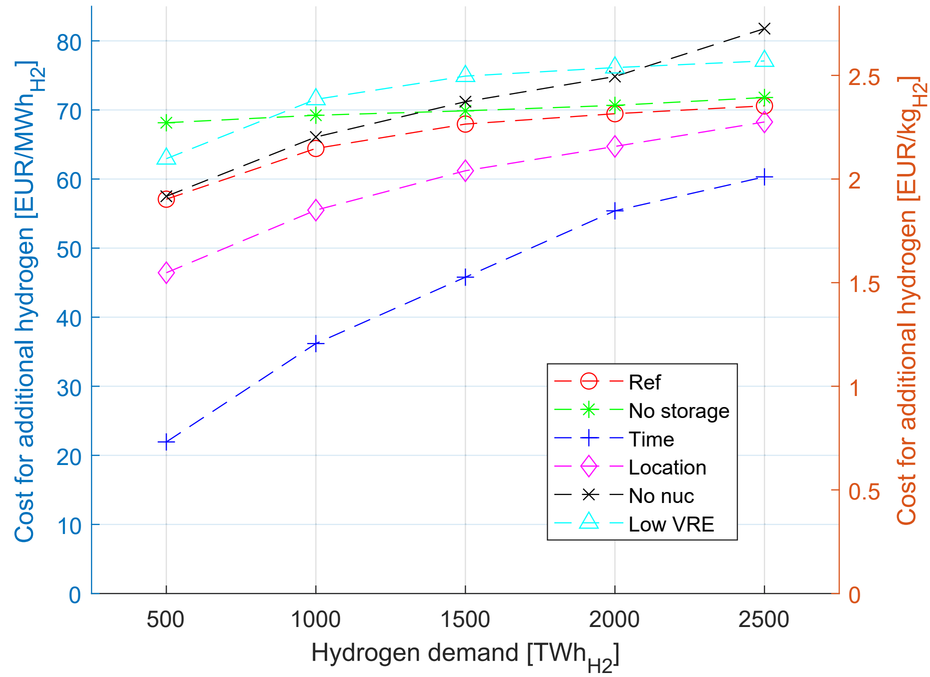

Fig. 3. The cost for hydrogen for the different cases and hydrogen demand levels (calculated as the difference between the total system cost for the considered hydrogen demand level and that for the previous hydrogen demand level, divided by the difference in hydrogen demand). The two vertical axes show different units for the cost of hydrogen.

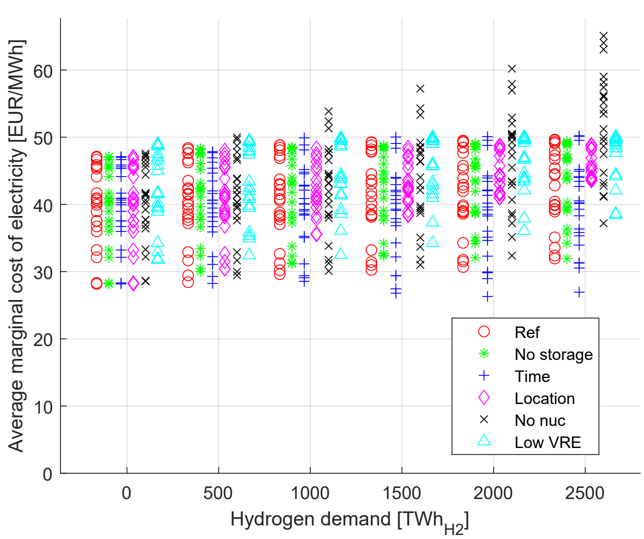

Fig. 4. Annual average electricity price for each modelled region for the different cases as a function of the demand for hydrogen.

TWh_{H2}), investments in transmission in the *Time* case exceed those in the *Ref* case, facilitating access to solar resources in the southern parts of Europe. The transmission cost stands out in the *No Nuc* case. There are strong incentives to trade electricity between regions in the *No Nuc* case, so as to access the limited VRE resources. An alternative to trade would be to use biofuels, although this would be a very expensive option for securing bulk electricity for hydrogen production.

In the *Ref* case and *Low VRE* case, the investments in hydrogen storage and electrolyser capacity level off with an increased demand for hydrogen, since the hydrogen demand is met to an increasing extent by nuclear power. In the *No Storage* case, the electrolyser capacity is designed without over-capacity. At the same time, the battery storage increases linearly with the demand for hydrogen, and the system needs up to 1 TWh more of battery storage compared to the *Ref* case, in order to handle variations in solar power. In the *Low VRE* case, which has the largest share of nuclear power, the investments in hydrogen storage, batteries and transmission are the lowest.

4. Discussion

The time-frame of the present study is not specified, although it points towards mid-century for three reasons: i) the higher end of the hydrogen demand investigated in this work is set to the upper levels of the European hydrogen pathway [1], ii) full decarbonisation of the electricity system is assumed, and iii) the technology costs are set to the projected Year 2050 levels. In order to isolate the impact of the hydrogen demand on the electricity system, different levels of demand for hydrogen are investigated. This work shows that the potential amounts of hydrogen may be cost-efficiently produced primarily from wind and solar power in Europe if the expansion of wind and solar power is not hindered by a lack of social acceptance. The results indicate that the average annual cost of electricity increases slightly with increased demand for hydrogen, as inferior resources are brought into play. However, local learning may incentivise regional energy and industry hubs with reduced costs for electricity and hydrogen as the system grows. The levels of acceptance of wind and solar power vary between regions, and even the expansion of wind and solar power in the *Low VRE* case may be challenging to realise in some regions. The *Low VRE* case lumps together limitations for onshore wind, offshore wind, and solar, in order to examine the impacts of low levels of renewables in total. However, the VRE technologies may not be interchangeable from the perspective of social acceptance.

The cost of hydrogen in this work is far lower than that reported by Lux and Pfluger (2020) [16], despite the fact that they model hydrogen consumption with the combined flexibility of the *Time* and *Location* cases of this work. The discrepancy cannot be explained by their reliance on 100 % renewables, as that is also the case in, for example, the *No nuc* case in the present study. Instead, it has to do with differences in generation costs for wind and solar power, which are extremely high in their work compared to the costs in the present work. The cost for hydrogen is

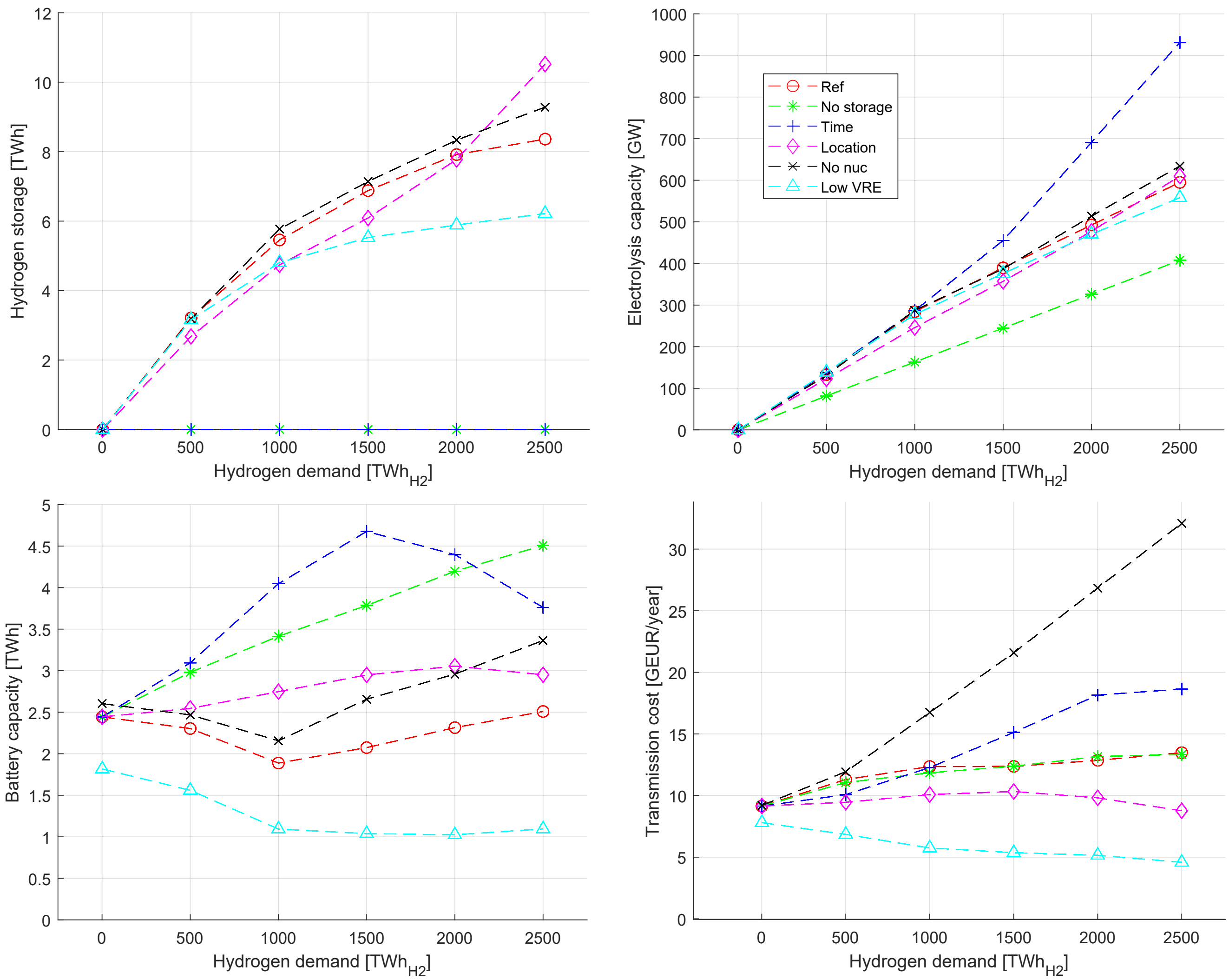

Fig. 5. Top left: Total H_2 storage; Top right: Total electrolysis capacity; Bottom left: Total battery storage capacity; Bottom right: Total annualised spending on transmission lines between regions.

sensitive to the assumed cost for electricity-generating technologies. The costs applied in the study of Lux and Pfluger (2020) [16] correspond to the contemporary (as in the time of their work) costs of electricity generation from wind and solar power, while the costs applied in this work are based on projections made for Year 2050 by the Danish Energy Agency [23].

The hydrogen storage cost assumed in this work is potentially conservative and thus two cases with costs representing salt cavern storage are presented in Appendix F. Low-cost storage result in several times larger savings potential from flexibility in storage and in even larger storage requirements. Salt cavern storage is still only used in a few locations globally and the geology is not available for all European regions. The availability of salt cavern storages for hydrogen could be an important driver for hydrogen usage and flexibility in the areas where the opportunity is present.

In this work, hydrogen production is modelled as part of the centralised electricity grid. The results indicate that when there is a high demand for hydrogen, the benefits obtained from integrating the hydrogen production into the centralised grid decline. Thus, at high hydrogen demand levels, large scale standalone/island systems for hydrogen production that are supplied by combinations of dedicated solar, wind and nuclear power plants may be attractive options. The potential benefits for standalone systems, such as the reduced costs for regional and distribution grids, are not captured by the model applied in this work.

The option of transporting hydrogen through pipelines is not included in this work. The *location* case partly captures some features of such a system, without taking the costs of the infrastructure into account. In the *location* case the regions jointly meet the total hydrogen demand of Europe. Thus, differences in resource availability for low cost wind and solar power are overcome and temporal variations in generation are smoothened. With a pipeline, trade of hydrogen could reduce differences in resource availability and balance temporal variations in the trading regions to some extent. Thus, introducing the possibility to invest in pipelines in the ref case, and operate hydrogen trading through these, would likely push the results towards that in the *location* case.

In this work it is assumed that the decentralized heating demand currently supplied by natural gas in Germany and the UK is supplied by individual heat pumps. This is likely a solution which will be adopted also in other countries to reduce the reliance on fossil fuels. Since the demand for electricity for heating is mainly allocated to wintertime, an increase in decentralized electric heating would drive additional investments in wind and solar power capacity available for hydrogen production in the summer. However, at the same time, a reduction in demand for heating and an increase in demand for cooling can be expected as the global average temperature increase as a consequence of climate change. The total impact of the development of the heating sector on the production of hydrogen in Europe could be interesting further work.

The results reveal that hydrogen production is achieved at a lower cost if the demand for hydrogen is allocated to regions with high availability-levels of wind and solar power resources. However, outside of the modelled world, the allocation of hydrogen demand also depends on strategic intangibles, such as knowledge and security of supply, as well as quantitative values, such as access to fresh water and distance to the product-demand. Still, low-cost electricity is likely to be an important driver, as seen in plans for the localisation of large hydrogen-consuming steel and ammonia plants in the Nordic countries [24,25] and in Spain [26,27]. The allocation of large electricity consumers to regions with high availability of wind and solar resources may, in turn, result in more geographically uniform electricity prices, as observed for the *Location* case. The allocation of hydrogen demand and production to regions with extensive wind and solar power supply in turn reduces the need for nuclear power and the need for transmission grid expansion. Globally, regions with good solar resources year-round may be able to produce hydrogen at costs below that seen even in the *Time* case, as the utilisation of both solar PV and electrolysers can be higher. In a study conducted by Hampp and colleagues (2021), some renewable electricity-based energy carriers are shown to be cheaper when imported to Germany from other continents, as compared to when these are imported from neighbouring regions [28]. Thus, on the one hand, low-cost hydrogen from a global market may limit the production of hydrogen within Europe and reduce the strain on European resources, on the other hand it may result in localisation of energy intensive industries outside of Europe.

Many sectors envisage hydrogen as a key part of their solution to attain climate neutrality. The benefits of the inherited flexibility of this hydrogen demand to the electricity system are often highlighted. However, this work shows that the electricity system initially benefits from the flexibility of the hydrogen demand, which reduces the relative need for other flexibility options and increases the share of the electricity demand that can be supplied by wind and solar power. However, the magnitude of the benefit declines as the hydrogen demand increases. Instead, a large hydrogen demand creates challenges in terms of the depletion of sites for wind and solar installations and, eventually, a smaller share of the electricity demand being supplied by wind and solar power. Thus, when performing a bottom-up study of energy carriers for a certain part of a sector it is reasonable to assume that there is a rather large demand for hydrogen for other purposes. Otherwise, it is easy to be over-optimistic regarding the benefits that will accrue to the electricity sector from using hydrogen as an energy carrier in the specific sector.

5. Conclusions

Overall, most of the future European hydrogen demand can be cost-effectively met with wind and solar power at a cost of around 60–70 EUR/MWh$_{H2}$. The cost of hydrogen increases, and the value of flexibility diminishes with an increasing demand for hydrogen. The acceptance of wind and solar power constrains the amount of green hydrogen that can be produced. At high levels of demand for hydrogen or if the expansion of wind and solar power is limited, nuclear power can supply the electricity needed for electrolysis at a cost of less than the levelised cost of nuclear power and electrolysis (82 EUR/MWh$_{H2}$) due to systemic benefits.

The results show that in order to supply the demand for hydrogen, there must be investment in over-capacity of electrolysers with hydrogen storage, such that the hydrogen demand can be fully supplied for on average 1–2 days by the hydrogen storages. This flexibility in hydrogen production that arise from large-scale storage of hydrogen, initially benefits the electricity system by reducing the need for other types of flexibility measures and by allowing wind and solar power to supply a larger share of the total electricity demand. However, the economic impact of additional flexibility is reduced as the demand for hydrogen increases. Under the assumptions made in this work, the economic impact of additional flexibility conferred by hydrogen storage is insignificant for hydrogen demand levels $> 1{,}500$ TWh$_{H2}$.

Localising the hydrogen demands in areas with available resources to generate low-cost electricity can lead to higher levels of utilisation of sites with good wind and solar resources. The cost of hydrogen in Europe can be reduced by around 10 EUR/MWh$_{H2}$ by localising hydrogen demand and production strategically. The economic benefit derived from strategic localisation of consumption is in addition to the benefit associated with hydrogen flexibility from hydrogen storage. Moreover, localising the hydrogen demand in regions with the lowest cost for electricity evens out the differences in annual average electricity prices between regions and reduces the need for investments in transmission.

Highly flexible hydrogen consumption on a temporal basis can increase the possibility to use solar power as a source of electricity for hydrogen production in most regions of Europe. Flexible consumption in time, for example from flexible industrial processes, can be valuable, even though hydrogen storage is cheap compared to battery storage. The savings potential from full temporal flexibility of hydrogen consumption is around 3-times larger than that from strategic localisation (around 10–30 EUR/MWh$_{H2}$).

A transition to renewable electricity together with electrification of other sectors generates a large demand for renewable resources. A strong demand for hydrogen greatly increases the need for electricity generation. The results of this study indicate that high availability of resources, achieved by strategic localisation of hydrogen production, a strong acceptance of wind and solar power expansion or a low total hydrogen demand, and flexible industries will enable low-cost hydrogen production. Low-cost hydrogen will be achieved by working with both efficiency and flexibility measures for hydrogen consumers, and by fostering acceptance of wind and solar power.

CRediT authorship contribution statement

Viktor Walter: Conceptualization, Formal analysis, Methodology, Visualization, Writing – original draft. **Lisa Göransson:** Supervision, Writing – original draft, Writing – review & editing. **Maria Taljegard:** Writing – review & editing. **Simon Öberg:** Writing – review & editing. **Mikael Odenberger:** 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.

Appendix A

The model applied in this work is a cost-minimising regional investment model, which was first presented by Göransson et al. (2017) [17] and updated subsequently, most recently by Toktarova et al. (2022) [13]. In this work, it has been run with several different ways for modelling the demand for hydrogen. All variables that are not connected to costs or emissions have non-negativity constraints. The sets (upper-case letters), parameters (italic upper-case letters) and variables (italic lower-case letters) for the equations are listed below.

T – The set of all time-steps
P – The set of all technologies
R – The set of all regions
Subsets of P:
P^{el} – Includes all electricity generation technologies
P^{VRE} – Includes 12 onshore wind power classes, off-shore wind power and solar PV
c^{tot}– The total system cost
C_p^{inv}– The annualised investment cost of technology p.
C_{trans}^{inv}– The annualised investment cost of transmission.
$i_{p,r}$– The capacity investments in technology p in region r.
$C_{p,t}^{run}$– The running cost of technology p in time-step t.
$g_{p,t,r}$– The generation from technology p in time-step t in region r.
$F_{r,r2}$– The distance between region r and $r2$.
$i_{r,r2}^{trans}$– The capacity investments between region r and $r2$.
$D_{t,r}$– Demand of electricity at time-step t in region r.
$z_{t,r,r2}$– The electricity-export from region r to region $r2$ in time-step t.
$D_{t,r}^{H_2}$ – Demand of hydrogen at time-step t in region r.
$R_{p,r}$– Capacity limit for investments in wind and solar resources for technology p in region r.
$W_{p,t,r}$– The profile limiting the weather-dependent generation for technology p and time-step t in region r.
$s_{p,t,r}$ – State of charge of (storage) technology p at time-step t in region r.
$b_{bat,t,r}^{ch}$– Charging of batteries at time-step t in region r.
$b_{bat,t,r}^{dis}$– Discharging of batteries at time-step t in region r.
η_p– Efficiency of technology p.
$I_{t,r}$– Inflow of energy to hydropower reservoirs at time-step t in region r.
$p_{electrolyser,t,r}$– Electricity consumption in electrolysers at time-step t in region r.
X_t– Weight of time-step t.

The objective function of the model can be expressed as:

$$\min c^{tot} = \sum_{r\in R}\left(\sum_{p\in P}\left(C_p^{inv} i_{p,r} + \sum_{t\in T}\left(C_{p,t}^{run} g_{p,t,r} X_t\right)\right) + \sum_{r2\in R\backslash r}\frac{1}{2}C_{trans}^{inv} F_{r,r2} i_{r,r2}^{trans}\right) \tag{E1}$$

The demand for electricity has to be met at all time-steps in all regions:

$$\sum_{p\in P^{el}} g_{p,t,r} + b_{bat,t}^{dis} \geq D_{t,r} + b_{bat,t,r}^{ch} + p_{electrolyser,t,r} + \sum_{r2\in R\backslash r} z_{t,r,r2}, \forall t \in \mathrm{T}, r \in \mathrm{R}. \tag{E2}$$

Generation has to stay below the installed capacity, weighted by profile, $W_{p,t,r}$, which is weather-dependent for wind and solar power (but constantly equal to 1 for thermal technologies):

$$g_{p,t,r} \leq i_{p,r} W_{p,t,r}, \forall t \in \mathrm{T}, r \in \mathrm{R}, p \in \mathrm{P}^{el} \tag{E3}$$

Investments in wind and solar power cannot exceed the regional resources capacity:

$$i_{p,r} \leq R_{p,r}, \forall p \in \mathrm{P}^{VRE}, r \in \mathrm{R} \tag{E4}$$

Batteries are implemented in the model with the following energy balance constraint for the batteries:

$$s_{bat,t+1,r} \leq s_{bat,t,r} + X_t\left(\eta_{bat}^{ch} b_{p,t,r}^{ch} - b_{bat,t,r}^{dis} \big/ \eta_{bat}^{dis}\right), \forall t \in \mathrm{T}, r \in \mathrm{R} \tag{E5}$$

All balance equations (E5, E9, and E10) are treated as cyclical, so that the first and the last time-steps of the year are connected.

The charge and discharge volumes are limited by the battery capacity, which is sized endogenously.

$$b_{bat,t,r}^{ch} \leq i_{bat\_cap,r}, \forall t \in \mathrm{T}, r \in \mathrm{R} \tag{E6}$$

$$b_{bat,t,r}^{disch} \leq i_{bat\_cap,r}, \forall t \in \mathrm{T}, r \in \mathrm{R} \tag{E7}$$

The battery storage volume is limited by:

$$s_{bat,t,r} \leq i_{bat,r}, \forall t \in \mathrm{T}, r \in \mathrm{R} \tag{E8}$$

Similar to E5, hydropower storage and hydrogen storage balances are modelled as described in E9 and E10, respectively.

$$s_{hydropower,t+1,r} \leq s_{hydropower,t,r} + X_t\left(I_t - g_{hydropower,t}\right), \forall t \in \mathrm{T}, r \in \mathrm{R} \tag{E9}$$

where $s_{hydropower,t}$ is limited to 60 % the current reservoirs. As some of the reservoirs are left for balancing inter-annual variations:

$$s_{H_2,t+1,r} \leq s_{H_2,t,r} + X_t\left(\eta_{electrolyser} p_{electrolyser,t,r} - \frac{g_{FC,t,r}}{\eta_{FC}} - D_{t,r}^{H_2}\right), \forall t \in \mathrm{T}, r \in \mathrm{R}$$

where $s_{H,t}$ is limited by the investment in hydrogen storage, $p_{electrolyser,t}$ is the hourly electricity consumption in electrolysers, which is limited by the electrolyser investments, and $g_{FC,t}$ is the electricity consumption in fuel cells. The demand of hydrogen is however flexible in time in the *time* case and in space in the *location* case. Thus, in the *time* case the model to optimise when the regional demand should be met over the year. In the *location* case the size of the regional demand is optimised, but the time-resolved demand represents $1/8760^*X_t$ of the regional demand for each timestep.

Appendix B

Table 2 gives the investment and variable costs for the electricity generation technologies considered in the model. The investment costs and fixed operational and maintenance (O&M) costs are based on those given in the World Energy Outlook 2016 [29], with the exception of the costs for solar PV and wind power, which are obtained from the Danish Energy Agency [23]. The O&M costs, as well as the fuel costs for nuclear plants are set in accordance with those presented by Kan et al. (2020) [30]. In the model, annualised investment costs are applied assuming a 5 % interest rate and the technical lifetimes. The cost and technical data for batteries and hydrogen technologies are shown in Table 3 [23]. Transmission cost is modelled in terms of the distance between strong grid points in the neighbouring regions and is 1.85 k€/MW/km, based on the average cost of HVDC (high voltage direct current) projects in Europe. Fuel costs are listed in Table 4.

The wind and solar supply profiles and available capacities for different resource classes are calculated using the tool developed by Mattson et al. (2021) [21]. The potential capacities are shown in Table 4, and their respective full-load hours are listed in Table 5. Hydropower is included, with average annual generation as the limit for inflow. Overall, 60 % of the hydropower storage is allowed to be used for the intra-annual variability in the cases of hydropower with storage. Nuclear power flexibility is modelled as the potential to vary production output between 70 % and 100 % of the installed capacity.

Table 2
Costs and technical data for the electricity generation technologies.

Technology	Investment cost [M€/MW(h)]	Variable O&M costs [€/MWh]	Fixed O&M costs [k€/MW/yr]	Life-time [yr]	Efficiency [%]
Biomass ST	2.0	2.1	52	40	35
CCGT[a]	0.90	0.8	17	30	61
GT[a]	0.45	0.4	15	30	42
Nuclear	4.0	6.6	95	60	33
Solar PV	0.3	0.5	7	40	100
Onshore wind	1.0	1.1	13	30	100
Offshore wind	1.5	1.1	36	30	100

[a] Fuelled with biomethane.

Table 3
Costs and technical data for the variation management technologies. The costs for electrolysers, battery capacity and fuel cells are given per MW and the costs of the batteries and hydrogen storage are given per MWh.

	Investment cost [M€/ MW(h)]	Efficiency (charge/discharge) [%]	Fixed O&M costs [k€/MW(h)/yr]	Life-time [yr]
Battery, Li-ion (energy)	0.08	96/96	–	25
Battery, Li-ion (capacity)	0.07	100	0.5	25
Electrolyser	0.4	70	18	20
Fuel cell	0.5	50	55	10
H_2 storage	0.011	100	–	40

Table 4
Costs and carbon intensities for the fuels used in this study.

	Fuel cost [€/MWh_{th}]	Carbon intensity [tonne/MWh_{th}]
Biomass	30	0.40*
Biogas	62.9	0.21*
Uranium	3.0	0

* Biogenic emissions are not accounted for if emitted.

Table 5
Potential capacities for the four onshore wind classes (C1-C4), Offshore wind and Solar PV, for each modelled region. These values are halved in the Low VRE case.

	Wind onshore C1	Wind onshore C2	Wind onshore C3	Wind onshore C4	Wind offshore	Solar PV
ALP_W	6	3	2	1	5	149
ATCZSK	23	22	2	0	0	187
BAL	7	57	7	0	24	303
BENELUX	3	5	2	1	7	54
CRSIHU	28	6	0	0	6	115
DE_N	20	19	10	3	23	139
DE_S	35	5	0	0	0	168
FI_T	34	63	7	1	26	56
FR_N	27	68	16	1	14	305
FR_S	24	17	5	1	4	240
IB_E	79	40	2	0	4	547
IB_W	24	8	1	0	6	129
IE_T	0	0	3	24	9	255
IT_S	21	6	0	0	11	70
NO_T	20	26	31	26	11	671
PO_N	8	30	5	0	4	94
PO_S	18	40	0	0	0	161
ROBGGR	59	10	2	0	7	306
SE_N	69	31	10	5	7	73
SE_S	34	33	8	2	34	54
UK_N	2	8	9	6	10	147
UK_S	0	4	23	8	20	176

Appendix C

See Fig. 6.

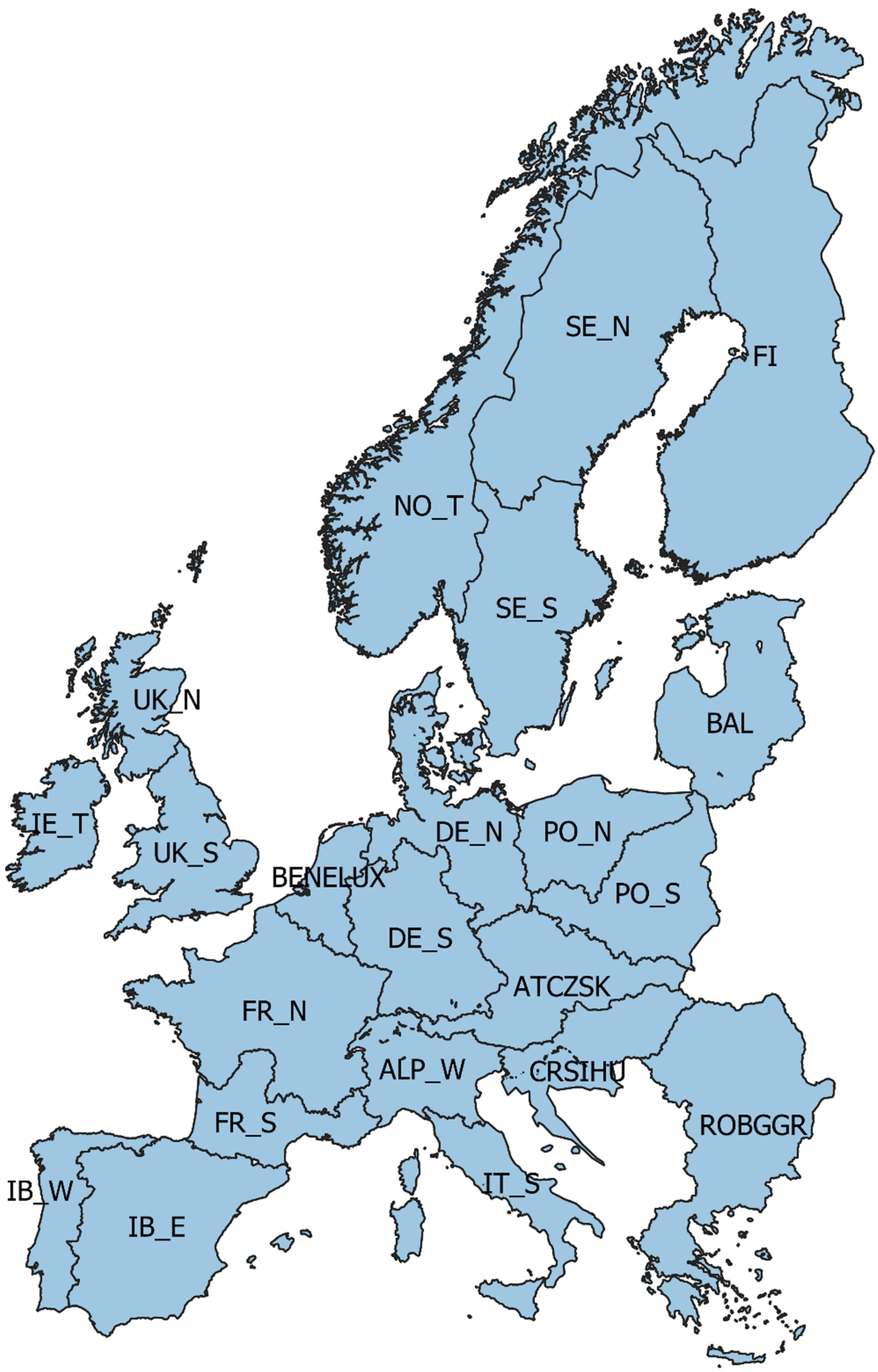

Fig. 6. Map of the modelled regions.

Appendix D

The general demand for electricity, as well as the additional demands for the transport sector and heating sector are given in Table 7.

Table 6
Potential full-load hours for the four onshore wind classes (C1-C4), Offshore wind and Solar PV, for each modelled region.

FLH	Onshore C1	Onshore *C*2	Onshore C3	Onshore C4	Wind offshore	Solar PV
ALP_W	1867	2554	3217	3973	1891	1720
ATCZSK	1894	2507	3159	3862	0	1485
BAL	2000	2494	3085	3894	4428	1178
BENELUX	1780	2498	3203	3922	4545	1277
CRSIHU	1833	2430	3134	3718	2246	1666
DE_N	1848	2434	3266	4088	4606	1269
DE_S	1731	2294	3135	3735	0	1408
FI_T	1982	2428	3235	3962	4325	1048
FR_N	1942	2568	3128	3873	4160	1532
FR_S	1928	2526	3251	3849	3566	1711
IB_E	1900	2504	3134	3797	2954	2102
IB_W	1908	2475	3201	3991	3454	1852
IE_T	1983	2738	3445	4257	4957	1141
IT_S	1939	2454	3053	3544	2447	1877
NO_T	1889	2572	3250	4042	4130	1042
PO_N	1878	2568	3087	3875	4429	1286
PO_S	1918	2505	3013	3769	0	1318
ROBGGR	1833	2427	3270	4031	3062	1741
SE_N	1841	2389	3256	3919	4046	998
SE_S	1905	2410	3289	4001	4406	1220
UK_N	2020	2674	3328	4089	4793	1113
UK_S	2037	2733	3301	4000	4439	1191

Table 7
Annual electricity demand [TWh] by type for the modelled regions.

	General	Passenger electric vehicles	Electric trucks and busses	Decentralised heat pumps	Total electricity demand
BENELUX	200	43	9	0	252
SE_N	23	1	1	0	25
SE_S	116	16	9	0	142
DE_N	134	38	15	23	210
DE_S	357	104	38	56	556
BAL	31	8	6	0	45
PO_S	129	45	44	0	217
IE_T	43	8	4	1	56
NO_T	113	6	8	0	127
IB_W	80	21	13	0	113
IB_E	274	62	39	0	374
FR_S	108	20	10	0	138
FR_N	418	78	40	0	536
ALP_W	244	76	38	0	359
IT_S	152	51	28	0	231
ATCZSK	158	33	47	0	238
ROBGGR	158	40	31	0	230
CRSIHU	73	16	6	0	94
FI_T	79	10	13	0	101
UK_S	304	82	41	37	465
UK_N	28	8	4	4	43
PO_N	52	18	17	0	87
Total	**3273**	**786**	**460**	**121**	**4640,1**

Appendix E

The annual hydrogen production is exogenously modelled in the *Ref* case (values in Table 8), with the same values for the *No storage*, *Time*, and *Low VRE* cases. However, for the *Location* case, the annual regional hydrogen production is endogenous to the model, i.e., a model output (values in Table 9).

Table 8
Annual hydrogen demand [TWh_{H2}] for each total hydrogen demand level and model region in the Ref, No storage, Time and Low VRE cases. These parameters are exogenously set in proportion to the general electricity demand listed in Table 7 in Appendix C.

Ref	500	1,000	1,500	2,000	2,500
BENELUX	31	61	92	122	153
SE_N	3	7	10	14	17
SE_S	18	36	53	71	89
DE_N	20	41	61	82	102
DE_S	55	109	164	218	273
BAL	5	9	14	19	24
PO_S	20	39	59	79	99
IE_T	7	13	20	26	33
NO_T	17	35	52	69	86
IB_W	12	24	37	49	61
IB_E	42	84	125	167	209
FR_S	16	33	49	66	82
FR_N	64	128	192	256	319
ALP_W	37	75	112	149	187
IT_S	23	46	70	93	116
ATCZSK	24	48	72	96	121
ROBGGR	24	48	72	97	121
CRSIHU	11	22	33	45	56
FI_T	12	24	36	48	60
UK_S	46	93	139	186	232
UK_N	4	9	13	17	21
PO_N	8	16	24	32	39

Table 9
Annual hydrogen demand [TWh_{H2}] for each total hydrogen demand level and model region in the Location case. These are results from the model.

Location	500	1,000	1,500	2,000	2,500
BENELUX	0	0	0	0	0
SE_N	57	62	62	87	104
SE_S	0	35	73	100	111
DE_N	0	0	10	18	29
DE_S	0	0	0	0	0
BAL	3	29	67	117	190
PO_S	0	0	0	0	2
IE_T	36	55	62	75	85
NO_T	134	187	227	250	262
IB_W	0	25	108	116	121
IB_E	239	389	440	514	623
FR_S	0	93	122	165	193
FR_N	0	0	6	60	121
ALP_W	0	0	0	0	0
IT_S	0	0	0	0	0
ATCZSK	0	6	11	36	89
ROBGGR	0	34	170	219	232
CRSIHU	0	9	24	60	65
FI_T	0	23	38	69	127
UK_S	0	0	0	0	17
UK_N	32	45	66	79	83
PO_N	0	10	15	34	47

Appendix F

The cost of additional hydrogen if large scale storage in salt caverns would be available all over Europe to a storage cost of 10 % of the cost assumed in other cases is seen in Fig. 7. The impact of storage on the cost of hydrogen is greatly increased with a lower storage cost. Relative to the *No storage* case, the cost of hydrogen in the *Ref + Low cost storage* case is reduced 3 times more compared to the *Ref* case with more expensive hydrogen storage. At the two highest levels of hydrogen demand, optimized localization of the hydrogen demand with low cost hydrogen storage results in the lowest cost hydrogen. In the *Ref + Low-cost storage* case the hydrogen storage capacity increase from 94 TWh at a hydrogen demand of 500 TWh_{H2} to 290 TWh storage capacity at the demand of 2500 TWh_{H2}. Thus a 90 % reduction in cost result in about 30–40 times larger storage.

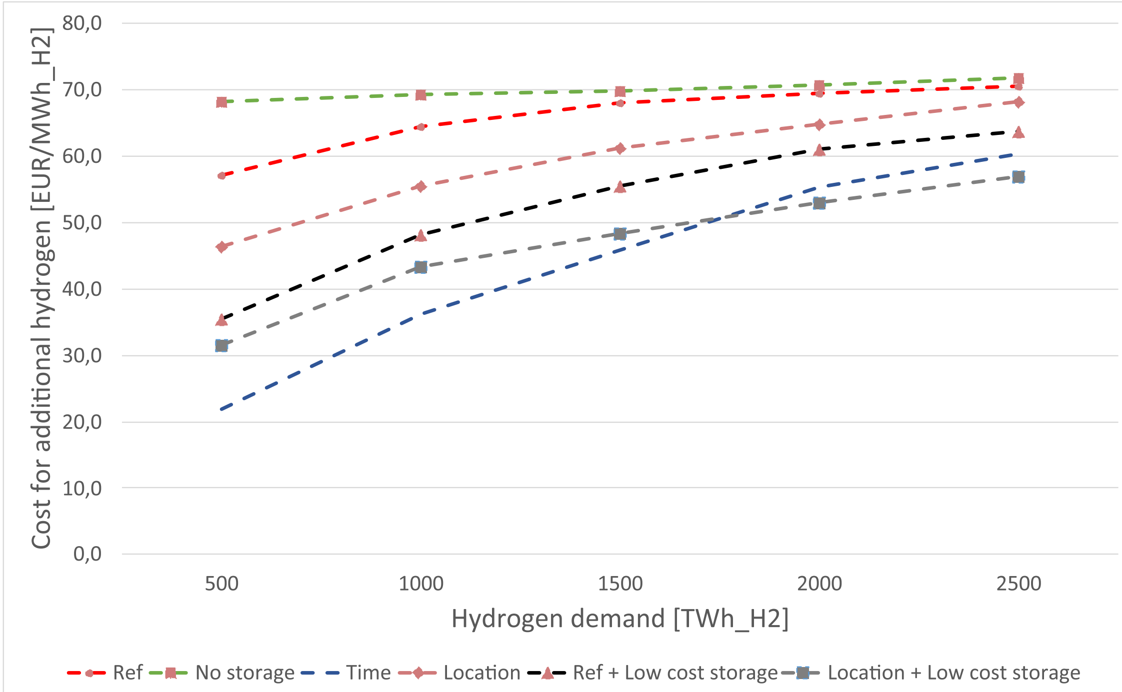

Fig. 7. Cost for additional hydrogen for the cases related to flexibility in time, place and storage, with the inclusion of the additional cases with low cost for hydrogen storage.

Appendix G

The total system cost subdivided into its different components for different levels of hydrogen demand for the Ref case and the Location case. Fig. 8 gives the total system cost for northern Europe without hydrogen demand. As the figure shows, the electricity production make up a majority of the cost, while investments in battery and transmission capacity to reduce geographical and temporal variations correspond to around 16 % of the total cost. Fig. 9 gives the change in total cost for the *Ref* case as hydrogen demand is added to the system. The cost for electrolysis and hydrogen storage correspond to about one third of the additional cost at low hydrogen demand levels but is reduced to around 20 % as the demand for hydrogen is increased and more of the hydrogen demand is met by nuclear power. In the *Location* case, given in Fig. 10, the cost of hydrogen storage and electrolysis remain a large share of the total cost also at a high hydrogen demand level since wind and solar power continues to meet a large share of the hydrogen demand.

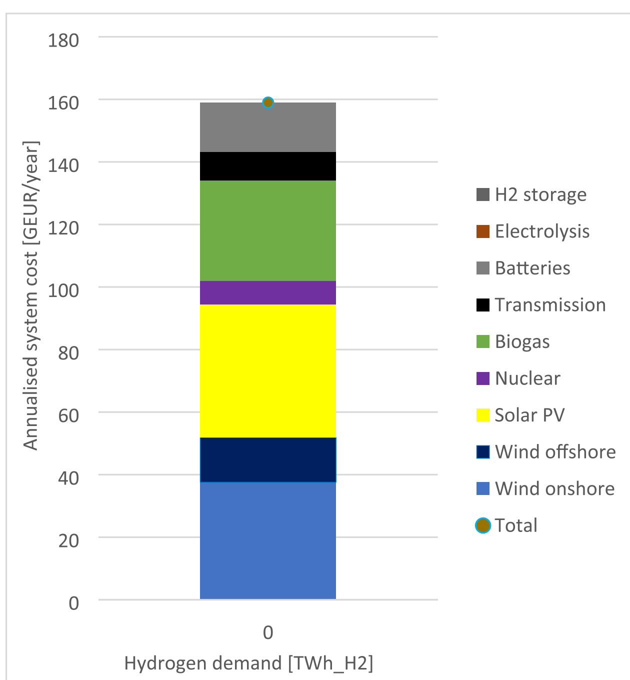

Fig. 8. Total system cost without demand for hydrogen subdivided into its cost components.

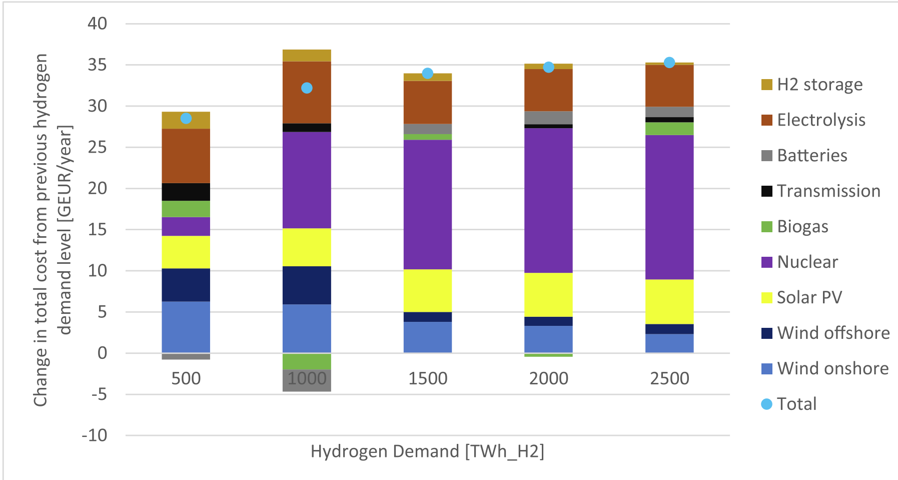

Fig. 9. Change in total cost for the Ref case as demand for hydrogen is added.

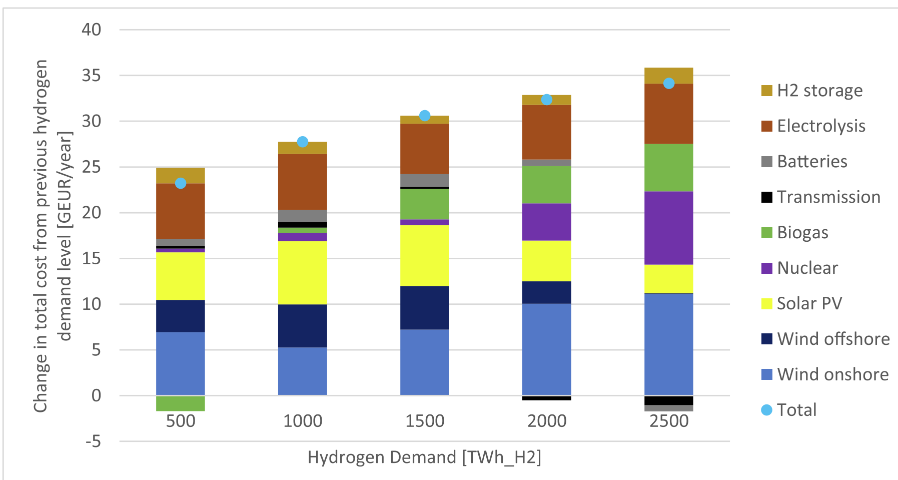

Fig. 10. Change in total cost for the Location case as demand for hydrogen is added.

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