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Are green and blue hydrogen competitive or complementary? Insights from a decarbonized European power system analysis

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ABSTRACT

Hydrogen will be important in decarbonized energy systems. The primary ways to produce low emission hydrogen are from renewable electricity using electrolyzers, called green hydrogen, and by reforming natural gas and capturing and storing the CO_2, known as blue hydrogen. In this study, the degrees to which blue and green hydrogen are complementary or competitive are analyzed through a sensitivity analysis on the electrolyzer costs, and natural gas price. This analysis is performed on four bases: what is the cost-effective relative share between blue and green hydrogen deployment, how their deployment influences the price of hydrogen, how the price of CO_2 changes with the deployment of these two technologies, and whether infrastructure can economically be shared between these two technologies. The results show that the choice of green and blue hydrogen has a tremendous impact, where an early deployment of green leads to higher hydrogen costs and CO_2 prices in 2030. Allowing for blue hydrogen thus has notable benefits in 2030, giving cheaper hydrogen with smaller wider socioeconomic impacts. In the long term, these competitive aspects disappear, and green and blue hydrogen can coexist in the European market without negatively influencing one another.

1. Introduction

Reducing greenhouse gas emissions is paramount to limit the effects of anthropological climate change. The European Commission [1] has developed a strategy for climate neutrality in 2050, and this includes reducing emissions associated with energy use and industrial activities. One way to eliminate emissions is through hydrogen. Hydrogen can be used as a way to store energy for intermittent renewable sources, and it can substitute other polluting industrial feedstocks.

Broadly, there are two main ways of producing hydrogen; using electricity through electrolysis, often called green hydrogen; and by reforming natural gas. The latter process emits CO_2, and if the CO_2 is captured and permanently stored, the hydrogen is typically labeled blue hydrogen.

The European Commission's strategy on hydrogen [2] favors hydrogen produced exclusively from renewable energy sources, as this produces hydrogen with little greenhouse gas emissions. Consequently, the European Commission has set a goal of building 80 GW of electrolyzer capacity by 2030; 40 GW in the European Union (EU) and 40 GW in neighboring regions that will supply the EU with hydrogen. Additionally, in the medium term, the European Commission acknowledge that other low-carbon hydrogen sources are necessary in order to support the future uptake of renewable hydrogen.

One potential sector that may synergize with green hydrogen deployment is blue hydrogen. These two hydrogen sources may share the same infrastructure, and one may potentially facilitate the uptake of hydrogen in potential demand sectors, thereby benefiting both. However, it is not clear to what degree these two hydrogen sources are complementary, *i.e.* positively influencing one another, or competitive, where the deployment of one impedes the market development of the other. All in all, the future development of hydrogen production technologies and natural gas markets is highly uncertain, and these can have significant implications on the deployment of green and blue hydrogen.

There is a need to start the deployment of hydrogen infrastructure soon in order to reach the goals for hydrogen deployment by 2030. However, it is not clear how much capacity of blue and green hydrogen should be built, and where it should be placed. Furthermore, the uncertain relationship between blue and green hydrogen is challenging for energy companies that want to build production capacity, and also system operators that wish to design transport networks. These organizations also rely on effective regulations by policymakers that must understand potential relationships between the two primary forms of hydrogen. This paper thus addresses the following open research

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questions, which are of interest to both policymakers and decision-makers in energy planning:

- How does the share of blue and green hydrogen capacity develop over time towards 2050?
- How do different realizations of the natural gas prices and the electrolyzer costs affect this distribution? What is the influence of these different costs on the price of hydrogen?
- How does the CO_2 price in the power sector change with the different costs for natural gas and electrolyzers?
- Are there any synergies between blue and green hydrogen in infrastructure development?

A capacity expansion model featuring the development of the power sector together with blue and green hydrogen production is used to answer these questions. The model simultaneously optimizes investments into the European power network, hydrogen infrastructure and blue and green hydrogen production capacities. The operations of these assets are considered in order to take into account changing levels of electricity demand and renewable power production, while meeting the European decarbonization goals for the power sector. This allows for the analysis of how blue and green hydrogen interact to meet the projected future European hydrogen demand while decarbonizing the power sector.

The article is structured as follows: Section 2 presents a review of available scientific literature and provides the academic context for this work. Section 3 presents the model used, and the central data of the work. Section 4 presents the results, initially with the base assumptions for costs, and then the results from the sensitivity analysis from Section 4.3 and later. Finally, the findings are summarized in Section 5.

2. Literature review

Hydrogen has garnered some relevant in academia, with studies including, for example, techno-economic analyses to produce hydrogen with the least cost for different scenarios, *e.g.* Yoshida et al. [3] that considered a Japanese case, Meier [4] who analyzed hydrogen production on a Norwegian offshore platform, and Kim et al. [5] who analyzed unit hydrogen costs as well as carbon footprints.

Almansoori and Shah [6] wrote a seminal paper in which they first applied optimization techniques to hydrogen supply chain design. They optimized for the least cost to satisfy a forecasted demand for hydrogen in the personal transport sector in the United Kingdom (UK). A similar model was used by [7] to study how to satisfy a given hydrogen demand in South Korea. Both of these implementations were deterministic and only considered a snapshot, *i.e.* there is no consideration for time; there is only a given hydrogen demand (over *e.g.* a year), which must be met with some assumptions on capacity factors for the producers. In Almansoori and Shah [8], the authors expanded the UK case study with a multi-stage model to consider the build-up of hydrogen demand and corresponding production capacity, as did Kim and Kim [9] for the South Korean model. Dayhim et al. [10] modified the original UK model to include stochastics, but kept the snapshot approach.

An important question that has garnered increasing attention is the questions of whether hydrogen in a decarbonized energy system should primarily be produced via electrolysis (*i.e.* green hydrogen) or from natural gas reforming with carbon capture and storage (CCS) (*i.e.* blue hydrogen). Ueckerdt et al. [11] performed a study to analyze when green hydrogen would reach cost parity with blue hydrogen, finding that in order for green to become competitive with blue hydrogen, a large share of renewable electricity is required to power the electrolyzers. They also show that green may become cost competitive with blue by 2035–2040. Blanco et al. [12] used the TIMES model to investigate the how different future realizations of the European energy market would affect hydrogen demand and production. They found that electrolysis production was a major source of hydrogen only when CCS was disallowed, and blue hydrogen was the major hydrogen source otherwise. This is reaffirmed by George et al. [13] who found that blue hydrogen does not seem to be a bridging technology for hydrogen (as is claimed by *e.g.* Ueckerdt et al. [11]), but instead is a dominant supplier also in the long term. This runs contrary to De-León Almaraz et al. [14], who studied the development of a hydrogen supply chain in Hungary. Using different objective functions as well as a multi-objective optimization, they found that blue and green would co-exist in the long term, but that the cost of hydrogen generally decreased when blue hydrogen was allowed. In broad terms, there are studies that argue that blue hydrogen plays a large role in a future decarbonized energy system, *e.g.* Al-Kuwari and Schönfisch [15] who studied the role of LNG in the emerging hydrogen economy; Parolin et al. [16] who studied a hydrogen delivery system for Sicily; Moreno-Benito et al. [17] who studied a domestic hydrogen supply chain in the United Kingdom; and Cloete et al. [18,19] who studied the interplay of carbon capture and storage with an energy system with high shares of renewables, using a stylized energy system model. There are also those that argue that green hydrogen can also play a significant role, such as Bødal et al. [20] who studied the joint development of electricity and hydrogen infrastructure in Texas and Zhang et al. [21] who studied the decarbonizing energy system in Victoria, Australia.

There have also been important review literature on hydrogen optimization by Agnolucci and McDowall [22], who reviewed literature on hydrogen supply chains across different spatial scales, Li et al. [23] who reviewed optimization techniques in hydrogen supply chain designs, and Fodstad et al. [24], who gave an up-to-date review on present challenges in energy systems modeling. These reviews have commonly noted how stochasticity is generally absent in studies on hydrogen supply chain optimization, which can have profound implications on energy systems dominated by renewable generators. The geographic scope of such works is also typically limited to a single country or area, without a detailed consideration for international trade of energy. Finally, the reviews note how it is common to only consider a snapshot temporal perspective, while arguing that such models should also consider the evolution of the hydrogen supply chains.

Taking the reviews above into account, as well as the works above, we note several important research gaps that we wish to address. First, as energy systems will have to undergo a transformation from today's reliance on fossil fuels to a system that is decarbonized, where hydrogen will play an increasing role, it is important to model how this evolution will take place. As a result, we argue that it is important to use a multi-period model. Also, the hydrogen market is closely interlinked with the electricity market, as electricity is used to produce green hydrogen, and hydrogen can be used to produce electricity. This close relationship must be explicitly modeled. Additionally, a decarbonized energy system is likely going to include large shares of renewable generation, and in order to make a robust supply chain, it is important to model the uncertainty associated with the generation from these. International trade should also be included, especially in an integrated energy market such as in Europe. Finally, optimization of hydrogen supply chains necessarily implements data about the future which is not clear, such as *e.g.* costs of electrolyzers for green hydrogen and natural gas costs for blue hydrogen. The actual costs for these may have profound implications for the development, but this is not commonly analyzed in literature.

These shortfalls are handled in this work, where the evolution of a hydrogen supply chain is optimized together with the European power sector in a capacity expansion model. Blue and green hydrogen will be used to satisfy an exogenous demand, but hydrogen can also be used in the power sector as decided by the model. The uncertainty associated with renewable generators is represented in detail in order to properly capture the available power to meet electric demand as well as for power production. A sensitivity analysis is also performed on central costs in order to see their effects on the evolution of the system. Table 1 highlights the contributions of this paper by comparing it with the closest available literature. The main contributions are:

Table 1
Comparison of this paper with most relevant literature.

Ref.	Optimization	Multi-period	Stochastic	Integrated el. grid	International trade	Sensitivity analysis[a]	Includes blue and green H_2
[4]				X			
[9,25]	X						
[17]	X	X					X
[14]	X	X					X
[6,8]	X	X	X				
[12]	X			X	X		X
This paper	X	X	X	X	X	X	X

[a]This work features an extensive sensitivity analysis with 225 realizations for important costs for green and blue hydrogen production. In this column, only other papers with such a large representation of the outcome space are included.

- Integrating the production of hydrogen with the electricity sector
- Including the stochastic nature of renewables and electricity demand in the power sector.
- Considering the European perspective in the electricity and hydrogen markets, allowing for international trade.
- Investigating the consequences that different realizations of projected costs have on the hydrogen market.
- Analyzing the degree to which blue and green hydrogen production can be competitive or complementary.

This paper addresses several of the research gaps brought forth by the review articles above and that are generally present in literature. This includes the simultaneous optimization of long-term investments with the short term characteristics of these. Furthermore, the deployment of green and blue will be influenced by the main costs of these, and the equilibrium of these is explored in this paper a sensitivity study. This gives increased insights into optimal investments into the hydrogen economy, and potential risks that policymakers and industrial actors need to consider.

3. Methods and data

A multi-horizon [26] stochastic [27] capacity expansion model called EMPIRE [28–30] is used in this work. The multi-horizon structure allows for uncertainty in both the long term strategic timescale as well as short term operations. EMPIRE minimizes investment and operational costs for power generation, transmission and energy storage. The model features a CO_2 cap for the power system in line with [1].

The temporal representation in EMPIRE consists of long term strategic periods and short term operational hours. There are five years between each strategic period, and new capacity can only be built in the strategic periods. The operational scenarios are embedded in each strategic period, where hourly dispatch is solved for four representative weeks of the year; one for each of the meteorological seasons. Additionally, two peak demand days are also considered in order to validate the investment decisions for high-demand periods. The results from these representative periods are scaled up to represent the costs for a representative year, and each operational scenario consists of one such representative year. This work includes three such operational scenarios per strategic period, in which the renewables generation and demand for electricity are subject to stochasticity.

EMPIRE was modified in [31] to also include green hydrogen production, transport and storage. Here, green hydrogen means hydrogen produced from electricity, irrespective of how that electricity is produced. The model featured hydrogen demand from [32] for industrial and transport use in each European country until 2050, and a constraint was included where this demand had to be met. This work expands this framework to also include blue hydrogen production. Hydrogen can be transported between the different countries through new hydrogen pipelines. The costs for the pipeline is from Jaro Jens, Anthony Wang, Kees van der Leun, Daan Peters [33], where the cost for the 48 inch pipeline has been linearized. Transporting gaseous hydrogen through pipelines also requires compression work, where the power is supplied

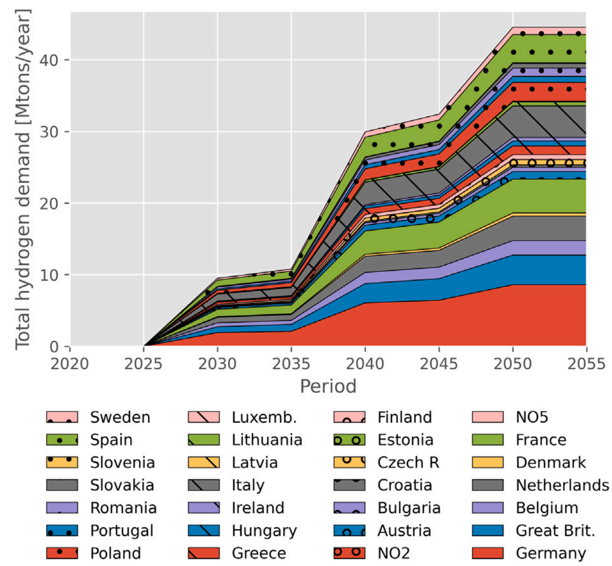


Fig. 1. Growth of hydrogen demand by country considered in this work.

from the grid. The necessary power per tonne of hydrogen is from Wang et al. [32], where the power requirement is split evenly between the sending and receiving country. All data and code used in the work is publicly available in [34]. The cost data for the different natural gas reformation technologies are from Table 21 in [35], and the technical details are from Table 22 in the same report. The hydrogen demand in each country is the sum of transport and industrial hydrogen demand from [32], and is shown in Fig. 1. The demand projection aligns well with the demand in the REPowerEU plan [36], which foresees 10 million tons per year of domestic hydrogen production (*i.e.*, within the EU) in 2030, where the demand in Fig. 1 includes 9.5 million tons per year in 2030.

The power sector in this work is subject to a CO_2 cap, in line with the European Commission's plan for climate neutrality in 2050 [1]. Blue hydrogen production uses natural gas to produce hydrogen, which is not covered by the CO_2 cap implemented for the power sector. The emissions associated with blue hydrogen production therefore incur an emissions cost, with the CO_2 price given in Table 2. This cost is intentionally set higher that the price realized in the power sector. If the cost of emissions is lower for blue hydrogen production than in the power sector, then there could be a case where it would be cost-efficient to circumvent the CO_2 cap in the power sector by producing blue hydrogen production for power generation. Here, it is ensured that this does not happen.

In this work, only the Netherlands, southern Norway and the United Kingdom can produce blue hydrogen, as these countries have direct access to the North Sea. The full carbon capture and storage (CCS) chain is not modeled, and instead the costs associated with this is included in the cost of the blue hydrogen production technology. The maximum

Table 2
Development of price of electrolyzers, natural gas and CO_2 emissions over time.

Period	Natural gas price [€/MWh] [37]	CO_2 price [€/t CO_2]
2020–2025	29.0	14.3
2025–2030	31.3	23.8
2030–2035	34.1	40.0
2035–2040	36.4	83.8
2040–2045	37.6	152.4
2045–2050	38.4	304.8
2050–2055	39.0	523.8
2055–2060	39.0	523.8

capacity of total blue hydrogen production in each country is 1000 t/h, roughly equal to the total capacity of Kårstøgas processing plant in Norway [38] in terms of energy output.

Green hydrogen production is hydrogen that is produced from electricity. In this work, this electricity is bought from the grid, as in [31]. The power associated with green hydrogen production with this definition will *not* lead to increased emissions from the power sector. This is because the model includes strict limits on the emissions from the power sector, and this constraint is consistently binding in the results. Since the CO_2 constraint is already at its limit, any additional power demand will by definition not increase the emissions; the added demand must be met without increasing the emissions. Green hydrogen, as modeled here, can therefore be considered emission-free. The real European carbon market is more dynamic that the hard carbon caps as implemented in this model, and the emissions from the power sector can increase with increased power demand, suggesting that green hydrogen can have a non-zero carbon intensity. However, given that the European Emissions Trading System (ETS) caps the overall CO_2 emissions, the added emissions from the power sector only displace emissions from another industry. The net climate change contribution is thus still nil. Blue hydrogen production also requires some electricity which is supplied by the grid.

This work features a sensitivity analysis where the electrolyzer capital and O&M costs, and the natural gas prices are varied. Initially, the capital and O&M costs for the natural gas reformers for blue hydrogen production were varied as well, but the natural gas price was found to be a more significant cost for this group of technologies. The costs were changed by multiplying the costs with a cost factor. These factors were equally distributed between 0.2 and 3.0 in steps of 0.2, giving 15 data points for each parameter and 225 combinations of natural gas prices and electrolyzer costs.

Using this sensitivity analysis, the degrees to which blue and green hydrogen are complementary or competitive are analyzed. In this work, complementary means that the two hydrogen sources can coexist or facilitate one another, whereas competitive means that investing in one is detrimental to the other. For example, if investing in blue hydrogen leads to a significantly reduced build-up of green hydrogen, then this is seen as competitive. On the other hand, if an initial investment into blue hydrogen leads to investments into pipeline infrastructure that is later also used by green hydrogen, then this is categorized as complementary.

Table 3 shows the cost development of the electrolyzers and the different natural gas reforming technologies included in this work. These costs only serve as the costs in the base case, and were varied in order to study different realizations of these costs. As the range of costs start at 20% of the costs listed in Table 3, and go up to 300% of the listed costs, the covered costs in the sensitivity analysis span much of the possible future costs of the production technologies.

4. Results and analysis

Throughout the results discussion, the base case is defined as the case where the cost factors are 1.0 for both parameters. In Sections 4.1 and 4.2, the temporal evolution of the relative shares of blue and green production capacity, and the price of hydrogen are respectively shown for the base case. Sections 4.4 and 4.5 present a sensitivity analysis on how the natural gas price and electrolyzer costs influence the price of hydrogen and the expected CO_2 price in 2030 and 2050. The potential re-use of infrastructure and complementary characteristics of blue and green hydrogen are discussed in Section 4.6. Finally, the constraint setting an upper limit for blue hydrogen production capacity is relaxed in Section 4.7, and the influence of hydrogen production on the European power market is discussed.

4.1. Share of total capacity between blue and green

Fig. 2 shows the share of blue and green production capacity over time for selected natural gas cost factors. It can be seen that for the base case (Fig. 2(a)), the blue completely satisfies all hydrogen demand until 2040, at which point green hydrogen enters the market with roughly 40% of the total hydrogen production capacity. Green hydrogen production capacity represents almost 60% the total capacity from 2050 and onwards, and blue remains a significant source of hydrogen throughout.

Increasing the cost of natural gas significantly changes this distribution. When the cost factor is 1.6 (Fig. 2(b)), it can be seen how green hydrogen is the largest source of hydrogen in 2040, and the share of green in 2040 increases when the natural gas cost factor is increased further (Figs. 2(c) and 2(d)). When the cost factor is 1.6, blue hydrogen is still a major producer before 2040, but for higher cost factors, green becomes more dominant even before this year. For very high natural gas costs (*e.g.*, when the price is 3 times the base price), green almost fully saturates the market throughout the investigated timeframe, but blue hydrogen still plays a minor role.

Note that a cost factor of 3 means that the natural gas price in 2050 is roughly 117 €/MWh, which is much higher than the prices historically seen in Europe. However, the natural gas price in Europe increased considerably in 2022, and prices around 100 €/MWh have been observed in the first half of 2022, whereupon the prices increased further in the second half of the year. The results presented here suggest that if the natural gas prices observed in 2022 are representative of the future gas prices in Europe, then blue hydrogen will likely not be an economical way to produce large quantities of hydrogen.

4.2. Temporal evolution of price of hydrogen

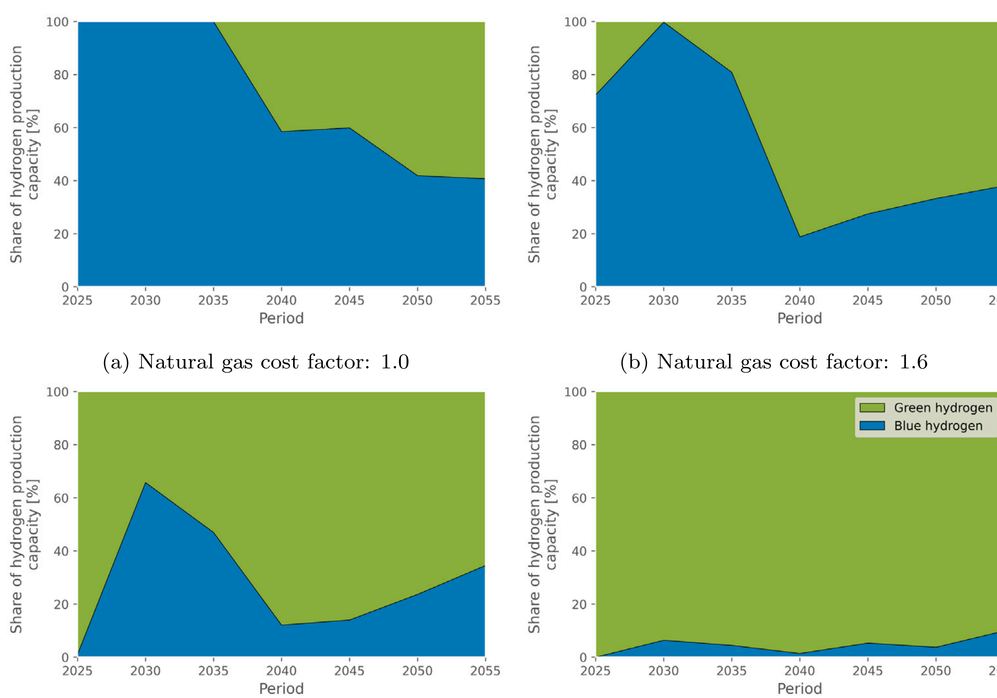
Fig. 3 shows the development over time of natural gas prices in Europe for different natural gas and electrolyzer cost factors. The reported hydrogen prices do not change much between the countries, and so only the German prices are reported here.

It can be seen in Fig. 3(a) that the cost of natural gas has a tremendous effect on the hydrogen price throughout the investigated time periods. The cheapest hydrogen is consistently achieved when the natural gas is cheapest, and in contrast, the highest prices are reached when there is no natural gas reforming. This illustrates how blue hydrogen has the potential to dramatically lower the price of hydrogen in Europe owing to its comparatively low costs when compared to the scale of production. The effect blue has on hydrogen is most pronounced in the short and medium terms, in the periods where it is also crucial to facilitate uptake of hydrogen in potential demand sectors. In 2030 for example, the price of hydrogen is reduced from 3.94 €/kg in the case without natural gas reforming to 1.72 €/kg when the natural gas price factor is 1. In the long term, *i.e.* in 2050, blue hydrogen still has an effect on the price, where the price of hydrogen is decreased from 1.33 €/kg to 1.02 €/kg. This shows that blue hydrogen has the potential to deliver hydrogen at a lower cost than green production, especially in the short and medium terms. Blue hydrogen may thus help start the European hydrogen economy by delivering hydrogen at a significantly lower cost in the short term.

Table 3
Development of costs for electrolyzers and natural gas reformers.

Period	2020	2025	2030	2035	2040	2045	2050	2055
PEM electrolyzer capital cost [€/kWe] [39]	1100	957	836	836	836	836	836	836
PEM electrolyzer fixed O&M cost [€/kWe][a]	55.00	47.85	41.80	41.80	41.80	41.80	41.80	41.80
PEM electrolyzer stack capital cost [€/kWe][b]	165.00	143.55	125.40	125.40	125.40	125.40	125.40	125.40
SMR capital cost [€/kW H_2] [35]	805	805	805	805	805	805	805	805
SMR fixed O&M cost [€/kW H_2] [35]	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8
SMR variable O&M cost [€/GJ H_2] [35]	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05
SMR CCS capital cost [€/kW H_2] [35]	1487	1487	1204	1204	1204	1204	1133	1133
SMR CCS fixed O&M cost [€/kW H_2] [35]	37.8	44.6	44.6	36.1	36.1	36.1	36.1	36.1
SMR CCS variable O&M cost [€/GJ H_2] [35]	0.53	0.53	0.07	0.07	0.07	0.07	0.07	0.07
ATR CCS capital cost [€/kW H_2] [35]	800	800	700	700	700	700	700	700
ATR CCS fixed O&M cost [€/kW H_2] [35]	34.0	34.0	24.0	24.0	21.0	21.0	21.0	21.0
ATR CCS variable O&M cost [€/GJ H_2] [35]	0.53	0.53	0.07	0.07	0.07	0.07	0.07	0.07
GHR ATR CCS capital cost [€/kW H_2] [35]	830	830	750	750	750	750	750	750
GHR ATR CCS fixed O&M cost [€/kW H_2] [35]	24.9	24.9	22.2	22.2	22.2	22.2	22.2	22.2
GHR ATR CCS variable O&M cost [€/GJ H_2] [35]	0.53	0.53	0.07	0.07	0.07	0.07	0.07	0.07

[a] Assumed 5% of capital cost.
[b] Assumed 15% of capital cost, based on Peterson et al. [40]. The electrolyzer stack is replaced every 8 years.



(a) Natural gas cost factor: 1.0

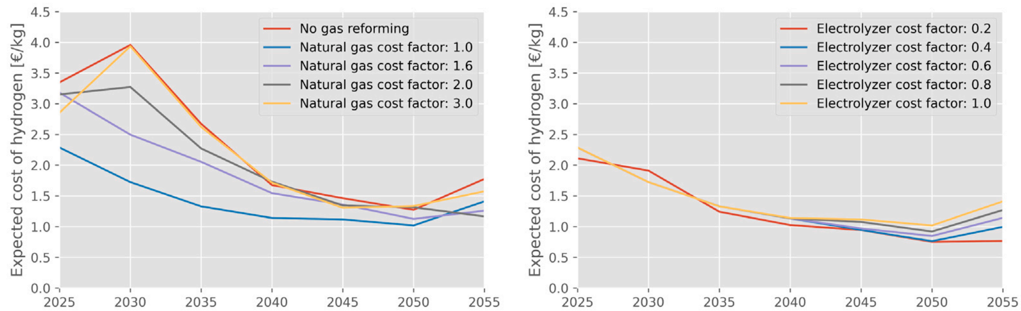
(b) Natural gas cost factor: 1.6

(c) Natural gas cost factor: 2.0

(d) Natural gas cost factor: 3.0

Fig. 2. Capacity share between blue and green hydrogen for selected natural gas factors. Electrolyzer cost factor = 1.0.

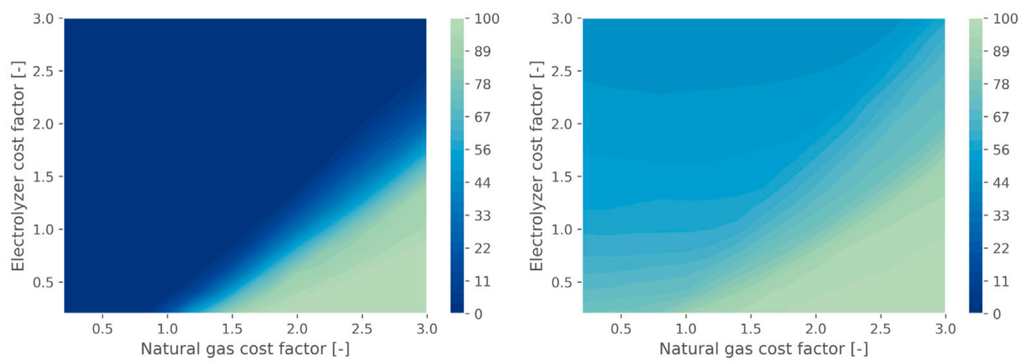
In contrast, the electrolyzer cost factor does not have as big of an effect when the natural gas cost factor is 1.0. For most cost factors, the price only diverges from 2045 on, and a significant short term change in the hydrogen price can only be observed when the electrolyzer cost factor is 0.2. In this case, the hydrogen price is only slightly reduced in 2025 (from 2.29 €/kg to 2.11 €/kg) when comparing the base case to the case when the electrolyzer cost factor is 0.2. In 2050, the reduction is from 1.02 €/kg to 0.75 €/kg. These findings are in line with what is shown in Fig. 2(a), where blue hydrogen is the main source of hydrogen until 2050, and so the effect of the electrolyzer costs is limited as long



(a) Variation with natural gas cost. Electrolyzer cost factor = 1.0.

(b) Variation with electrolyzer cost. Natural gas cost factor = 1.0.

Fig. 3. Development of price for H_2 in Germany for selected natural gas & electrolyzer price factors.



(a) Sensitivity in 2030.

(b) Sensitivity in 2050.

Fig. 4. Sensitivity of green hydrogen's share of total European hydrogen production capacity [%].

as green hydrogen does not hold a significant market share. Fig. 3(b) shows that electrolyzer costs would need to be lowered by 80% from the base case in order for green hydrogen to become a more significant source of hydrogen.

4.3. Sensitivity of capacity share to electrolyzer and natural gas costs

For a given level of hydrogen demand, blue and green hydrogen are competitive in the sense that a given unit of the demand can only be met by one or the other. This subsection therefore shows how the capacities of blue and green hydrogen production in 2030 and 2050 change with the different cost factors. This is shown in Fig. 4.

From Fig. 4(a) it is clear that in 2030, it is most optimal to produce hydrogen through natural gas reforming unless electrolyzer costs are significantly reduced and natural gas prices are higher than in the base case. For most of the cost factors, all of the hydrogen demand is satisfied exclusively by blue hydrogen. Also seen in Fig. 4(a) is how the band where blue and hydrogen coexist is very narrow, meaning that for most the data points, the hydrogen production capacity is almost entirely blue or green, suggesting that in the medium term, blue and green are entirely competitive.

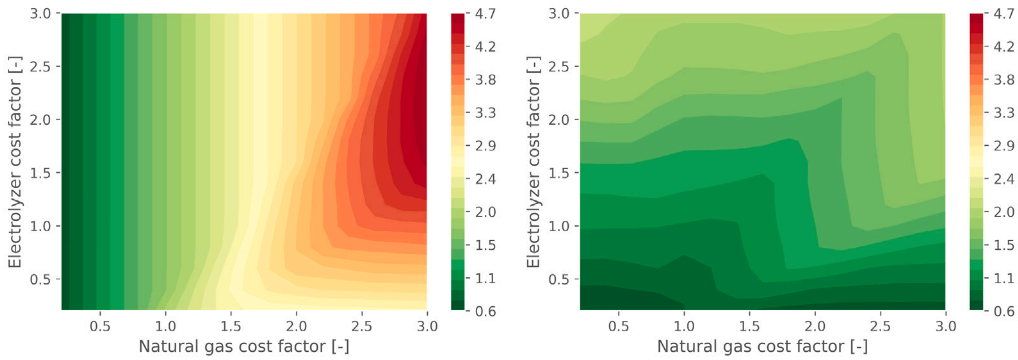
Fig. 4(b) shows that the capacities of blue and green hydrogen production are more even in 2050, and the supply is not completely saturated by either green or blue. This holds as long as the natural gas price is not very high, in which case all hydrogen is supplied through electrolysis. For those costs that are closer to the base case, the capacity is roughly equally split between blue and green, similar to what is seen in Fig. 2(a). This suggests that in the long term, the hydrogen market is large enough for both production methods to coexist, where natural gas reformers complements green hydrogen in the periods where the electrolyzers do not produce hydrogen.

4.4. Sensitivity of hydrogen price to electrolyzer and natural gas costs

In Fig. 5, the sensitivity of hydrogen price to natural gas and electrolyzers costs are shown for the years 2030 and 2050 respectively. In Fig. 5(a), it can be seen that for low natural gas costs, the contours are vertical, meaning that electrolyzer cost plays no significance. In these cases, blue hydrogen completely satisfies the hydrogen demand, and there are no electrolyzers in the optimal solution. These solutions also offer the lowest hydrogen price in 2030. As the natural gas price increases, green hydrogen takes a larger role as shown in Fig. 4(a), and so the contours show a sensitivity to the electrolyzer cost as well. As green hydrogen enters the market, the price of hydrogen increases too, which could have serious implications for the uptake of hydrogen as an energy carrier and industrial feedstock.

In 2050, the electrolyzer cost has a bigger effect, and the lowest costs are achieved when the electrolyzer cost factor is the lowest. The contours in Fig. 5(b) display a tendency to abruptly drop as the natural gas cost factor increases, and comparing with Fig. 4(b), it can be seen that this is the region where green hydrogen becomes the dominant producer of hydrogen in Europe. For a given electrolyzer cost, this means that once the natural gas price is high enough so that green completely outcompetes blue hydrogen production, the price of hydrogen will abruptly and substantially increase.

Comparing Figs. 5(a) and 4(a), it can be seen that the prices in 2030 are the lowest when blue hydrogen supplies all of the demand. It is also evident that prices rise tremendously in those cases where green is the main supply instead. Today, it is not clear how the hydrogen economy will start and what sectors will be the first users. But what is clear is that cheap hydrogen in large quantities will unquestionably help spur demand. In this way, blue hydrogen production increases the likelihood of uptake of hydrogen in demand sectors. This may have



(a) Sensitivity in 2030.

(b) Sensitivity in 2050.

Fig. 5. Average price of H_2 in Germany [€/kg].

significant benefits also to future green hydrogen production, as blue may initialize the hydrogen demand sector, which green hydrogen can subsequently use. This is in line with previous findings by *e.g.*, Ueckerdt et al. [11]. They found that blue hydrogen is highly competitive with green hydrogen in the near future, where the calculated price of CO_2 required for a fuel switch from fossil fuels to hydrogen is lower for blue hydrogen in both the primary steel and process heat sectors until 2040. Our results reaffirm this, showing how blue hydrogen is more cost-effective before 2050.

4.5. Sensitivity of co_2 price to electrolyzer and natural gas costs

Green hydrogen production will require significant amounts of electricity, which will require additional investments into the power grid. The European power market is also subject to the ETS, which will gradually reduce the allowable emissions quota in the power sector as well as other included sectors. As green hydrogen production can increase the power demand in Europe considerably, it may significantly increase the CO_2 price in the ETS, and in this section, the price of CO_2 if set by the power sector is analyzed as the European power sector reaches carbon neutrality in 2050. The sensitivity of the CO_2 price if set by the power sector, to the natural gas and electrolyzer costs are shown in Fig. 6.

Fig. 6(a) shows this sensitivity in 2030. It can be seen that the CO_2 price is relatively low in most cases, except for when the natural gas cost factor is high while the electrolyzer cost factor is low (the lower right triangle in the figure) or when the natural gas cost factor is low (the red area to the left in the figure). The explanation for the former region's high CO_2 price is that in 2030, the power sector is not notably decarbonized yet, and so there is not much renewable energy to use to produce hydrogen. At the same time, as shown in Fig. 4(a), this cost region is dominated by green hydrogen. This means that conventional generators are used to produce hydrogen, putting pressure on the carbon price.

Similarly, for the latter region with high CO_2 prices, what occurs is that because natural gas is so cheap (*i.e.*, the cost factor is well below 1.0), it becomes more favorable to produce electricity with natural gas, as the fuel costs are significantly reduced. Consequently, power generation with natural gas increases significantly, putting increased pressure on the CO_2 price.

In all other regions of Fig. 6(a), natural gas reforming is the main source of hydrogen, while natural gas is not as dominant in the power supply. As a result, the CO_2 price is much lower for these natural gas and electrolyzer cost factors.

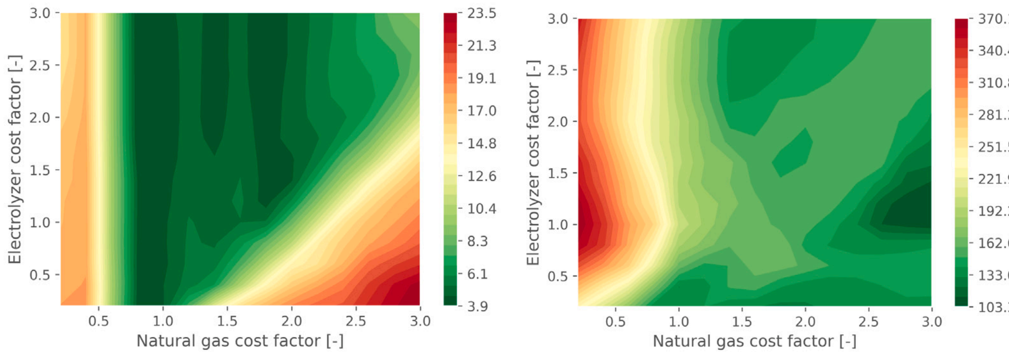
In 2050, as shown in Fig. 6(b), the distribution of CO_2 prices are a little different. The lower right hand triangle of high CO_2 prices cannot be found anymore, but there is again a region to the left in the figure with high CO_2 prices. This latter region is not as vertical as in Fig. 6(a), and the CO_2 prices in the lower left, *i.e.*, the region with low natural gas and electrolyzer cost factors, are lower than elsewhere in the leftmost region of the figure. As seen in Fig. 4(b), hydrogen is supplied both by blue and green hydrogen, and when the electrolyzers cost factors are low, it is possible to operate them with lower capacity factors while still being cost-efficient. What is seen in the results corresponding to the lower left corner of Fig. 6(b) is that electrolyzers are more decentralized, meaning that the capacities are spread over more nodes compared to when the electrolyzer cost factor is higher. Additionally, the electrolyzers are operated with smaller capacity factors. This is because when the electrolyzers can cost-efficiently operate with lower capacity factors, they can closer match their production with renewable power generation profiles and periods of lower electricity demand. This reduces the electrolyzers' reliance on dispatchable power generation, usually coming from fossil fuels, thereby reducing the pressure on the CO_2 price.

When the electrolyzer cost factor increases, the electrolyzers have to be run with higher capacity factors in order for the investment cost to be paid back. This necessitates more stable power production, and so dispatchable power generation is used to a higher degree. Since the leftmost region also coincides with lower natural gas cost factors, this dispatchable power is mainly in gas-powered power generators. This drives the CO_2 price upwards. Other dispatchable but low-carbon power generators, such as those based on nuclear energy and biomass, are also used to a higher degree when the electrolyzer cost factors increase.

Note that these CO_2 prices hinge on the assumptions we have made surrounding green and blue hydrogen production, where we assume that green hydrogen is completely emissions-free, and blue hydrogen only emits the non-captured CO_2 in the reforming process (where the capture rate is either 90% or 93% depending on the technology). These assumptions can be debatable. For example, green hydrogen production from solar photovoltaic energy can be associated with significant greenhouse gas emission [41]. Similarly, blue hydrogen can be associated with considerable greenhouse gas emissions if the upstream natural gas production suffers from large amounts of methane leakage [42]. The impact of methane leakage on how climate-friendly blue hydrogen is naturally different depending on geographic location, as upstream methane leakage varies between production regions, where for example Norway has among the lowest leakage rates in the world [43]. Furthermore, the impact of methane leakage is reduced with improved processes for natural gas reforming [44].

4.6. Sharing of infrastructure

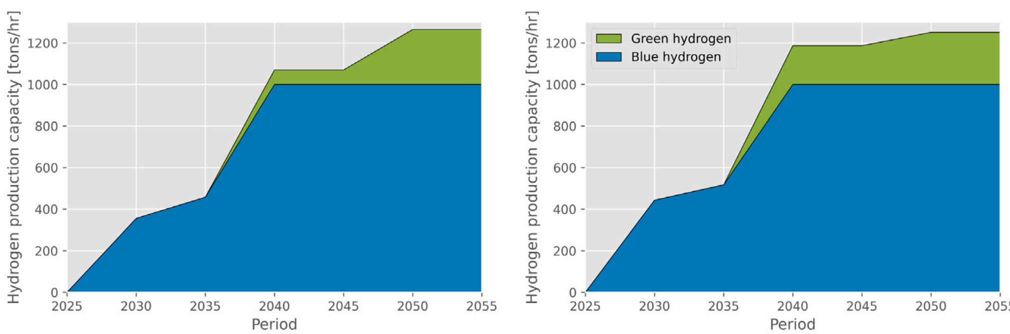
One area in which blue and green hydrogen can be complementary is in the development of hydrogen infrastructure that can be shared. Such infrastructure could for example be hydrogen pipelines. One



(a) Sensitivity in 2030.

(b) Sensitivity in 2050.

Fig. 6. Average CO_2 price in the European power sector [euro/t].



(a) Natural gas cost factor = 0.4.

(b) Natural gas cost factor = 1.0.

Fig. 7. Hydrogen production capacity in Southern Norway (NO2) for two natural gas cost factors. Electrolyzer cost factor = 1.0.

possible way for blue and green hydrogen to be complimentary is that and early build-up of blue hydrogen capacity – along with the associated pipeline capacity – may lead to reuse of the pipelines once the green hydrogen supply matures and the power system is decarbonized. Generally, this is not found in the results of this work. In most cases, the deployment of blue and green do not seem to be correlated, and the lack of deployment of natural gas reformers does not seem to influence a subsequent investment in electrolyzers. However, in some cases, it appears that there is a relationship between the two. Below is one such example.

Fig. 7 shows the development of hydrogen production capacity in southern Norway for two natural gas cost factors. It can be seen that in Fig. 7(a) the capacity of blue hydrogen in 2030 and 2035 is significantly smaller than in Fig. 7(b). In this example, the capacity in 2030 is reduced by 19.8%. Since less hydrogen is produced, there is less need for export pipelines, and so less transmission infrastructure is also built. Fig. 7 also shows how in 2040 and 2045, the build-up of green hydrogen in southern Norway is considerably smaller in Fig. 7(a) than in Fig. 7(b), with a 62.5% decrease in green hydrogen production capacity. The total hydrogen production capacity in southern Norway in 2040 is thus reduced by almost 10%. This suggests that the smaller early investment into blue hydrogen production capacity, and the corresponding pipeline capacity, reduces the medium term optimal investment into green hydrogen.

In the long term, Fig. 7 shows very little difference between the two cases. The complementary effects described here thus seem to be limited in that they only apply in the medium term, and so in the long term the capacity will be built up regardless. However, in cases where this effect is significant, this finding could have significant implications for those actors in the hydrogen market that want to establish themselves early. For them, it could be worthwhile to gain an early market position with blue hydrogen, and use this to build the necessary infrastructure that can be efficiently reused as green hydrogen is introduced.

4.7. *Unrestricted natural gas reforming*

Blue hydrogen production is limited to 1000 tons/hr in each of the three nodes, totaling 3000 tons/hr in Europe. While this maximum capacity is enough to supply the EU with 20 million tons of hydrogen in 2030, as in the REPowerEU plan from 2020 [45], it is not enough to fully meet all future demand of hydrogen. In Fig. 2(a), it is shown how in from 2040 onwards, green hydrogen production takes a significant share of total production capacity in Europe. What happens is simply that blue hydrogen reaches the maximum limit of total capacity, and green hydrogen needs to supplement blue hydrogen in order to satisfy the exogenous demand for hydrogen. In this section, the maximum limit for blue hydrogen production capacity is removed for the base case (*i.e.* the case where both cost factors are 1) in order to analyze the potential of blue hydrogen production.

Fig. 8 shows the share of blue and green hydrogen production capacity in Europe without maximum limits on blue. Here blue hydrogen production is the major producer of hydrogen by far in all periods, but does not supply all of the hydrogen to the market. Green still enters the market in 2040, but to a smaller degree than previously. This shows that blue hydrogen production is more cost efficient, but green still plays an important role in the European hydrogen market. As such, these two production methods are still complementary, even when blue hydrogen has no upper limit.

It is also interesting to consider the effects that these different hydrogen production methods have on the power sector in Europe. Blue hydrogen production requires significantly less electricity than green

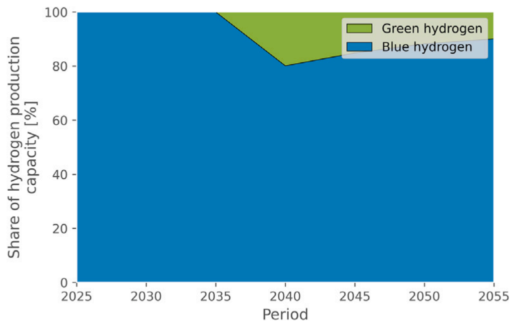


Fig. 8. Evolution of hydrogen production capacity with no limits on reformers. Natural gas and electrolyzer cost factors are 1.0.

hydrogen, and it is expected that the total installed power generation capacity will decrease as blue hydrogen substitutes green hydrogen. Fig. 9 shows the growth of total installed power generation capacity in Europe in four cases: a. when only green hydrogen can be produced; b. when there is no hydrogen production in Europe; c. when the maximum capacity of blue hydrogen production has an upper limit of 1000 tons/hr in each node; and d. when there is no limit on blue hydrogen production capacity.

The large share of blue hydrogen production as seen in Fig. 8 is in line with other literature. For instance, George et al. [13] found that blue hydrogen does not appear as a bridging technology between today and a future green hydrogen economy, but instead is highly competitive with green hydrogen also in the long term. Likewise, Moreno-Benito et al. [17] found that blue hydrogen dominated the supply of hydrogen in their case study on the UK. Here, green hydrogen only accounted for a large share of production only when CCS was disallowed. It therefore appears that there is the risk of having blue hydrogen dominating supply also beyond 2050, and that the limiting factors thus are availability of natural gas and CO_2 sequestration capacity.

In [31] it was shown how if Europe is going to meet all the hydrogen demand with green hydrogen, then the installed power generation capacity in 2050 would increase by almost 50%, compared to if there were no hydrogen production. The growth of the European power sector in the cases with just green hydrogen and without any hydrogen are recreated here in Figs. 9(a) and 9(b).

Fig. 9(c) shows that even in the case with limited blue hydrogen maximum capacity, the shift from green to blue hydrogen production brings significant savings in the power generation sector. The total European power generation capacity in 2050 is reduced from 3.6 TW to 2.9 TW, mainly in solar power that would otherwise drive green hydrogen production. When the upper limit for blue hydrogen production is removed, as is the case in Fig. 9(d), the savings in power generation are even greater, and the total European capacity is reduced further to 2.5 TW. This is almost equal to the total capacity when there is no hydrogen demand, as seen in Fig. 9(b).

Fig. 9 also gives insights into why in Fig. 6(a), the CO_2 price is highest in the lower right corner, where green hydrogen is the main source, as seen in Fig. 4(a). In 2030, the total installed capacity looks similar in all of the cases, and the large expansion of renewable generation has not yet happened. Consequently, in order to power the electrolyzers, the fossil-based generators are run with higher capacity factors, thereby putting increased pressure on the CO_2 price.

5. Conclusion

This paper has investigated the deployment of blue and green hydrogen production under different realization for natural gas prices and electrolyzer costs. Using this approach, the paper highlights potential ways in which blue and green may complement each other in the development of the hydrogen economy and ways in which they may be competitive.

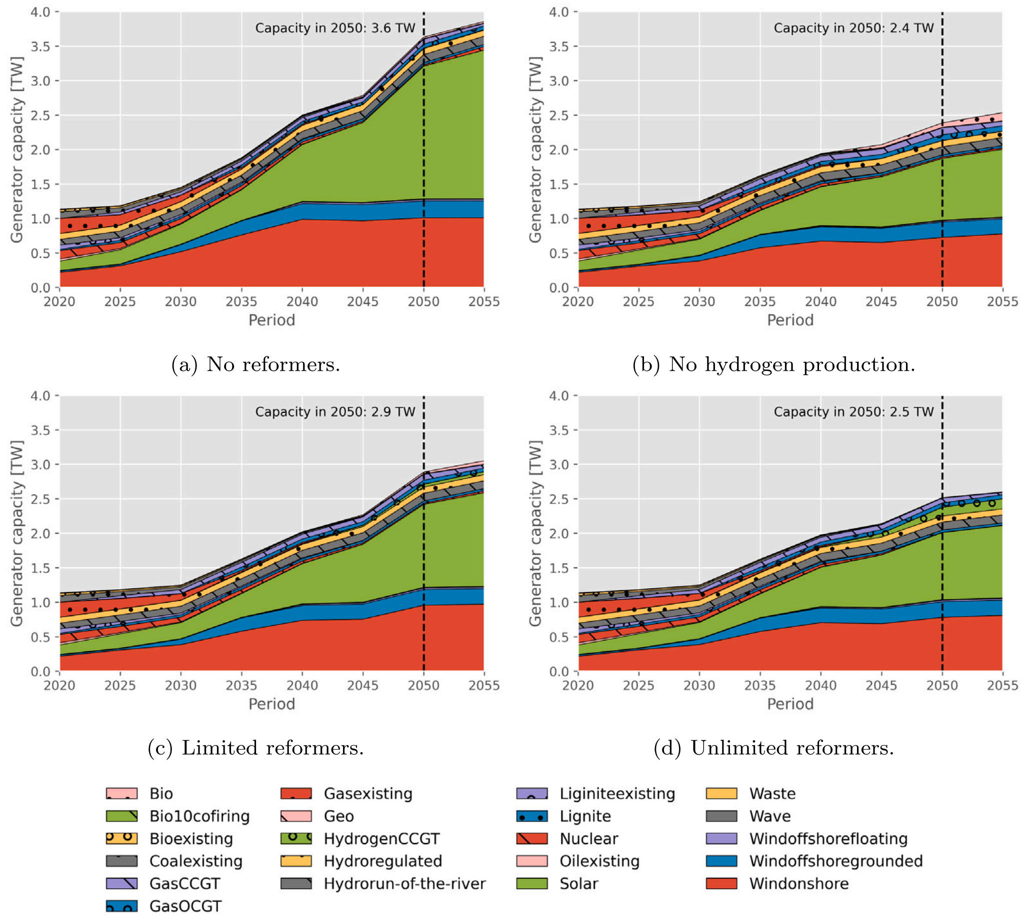
It is shown that blue hydrogen is a significant source of hydrogen supply in both 2030 and 2050 when the natural gas price is within typical levels prior to the current European energy crisis, and electrolyzer costs are not significantly cheaper than predicted by Bertuccioli et al. [39]. Blue hydrogen is favored because it can produce hydrogen at a much lower cost, and this significantly lowers the cost of hydrogen in 2030, where the cost of hydrogen is reduced by over 55% in the base case when blue hydrogen is allowed, compared to when green hydrogen is the only source. This finding for 2030 holds regardless of electrolyzer cost in this year, as the price of hydrogen is much more sensitive to the natural gas cost at this stage. If the cost of natural gas is at the levels seen during the energy crisis in Europe, then green becomes the primary source of hydrogen both in 2030 and 2050, leading to a significant price increase in both periods.

Blue and green hydrogen are potentially complementary in several ways. The following summarizes the ways we have discussed in this paper:

- **Blue hydrogen considerably lowers the cost of hydrogen in 2030.** With lower costs of hydrogen, it is likely that blue hydrogen production facilitates the uptake of hydrogen in marginal demand sectors. Once these demand sectors have implemented hydrogen technologies, they will be prepared to also use green hydrogen once electrolyzer capacities scale up. In this way, blue hydrogen may help expand the demand also for green hydrogen in the future.
- **Green hydrogen production can put significant pressure on the CO_2 price in 2030.** The European power system in 2030 still has a large share of fossil generators, which will need to be dispatched in order to power green hydrogen production. This will significantly increase the price of CO_2 in 2030. This is not seen in 2050, when the European power system is much more decarbonized.
- **Drawbacks with green hydrogen adoption appear time limited.** The issues with an early adoption of green hydrogen as found here, such as pressures on CO_2 prices, or a large increase in the price of hydrogen, are only seen in the medium term, *i.e.*, in 2030. By 2050, most of these drawbacks have been eliminated, allowing green and blue hydrogen to coexist in the hydrogen market.
- **Deployment of blue hydrogen production can lead to significant savings in the European power sector.** Exclusively producing hydrogen through electrolysis will require a tremendous expansion of power generation capacity in Europe. Using blue hydrogen to meet the hydrogen demand significantly reduces the necessary investments into power generation capacity, leading to significant savings in the energy system.
- **The competitive aspects between blue and green hydrogen are all short-term.** The competitive characteristics identified in this paper are all seen in 2030, including how either green or blue satisfies all demand, or how an early prioritization of green hydrogen leads to a high price for hydrogen. In 2050, this paper shows how green and blue hydrogen are complementary in every investigated aspect.

Summarizing the findings into practical recommendations, it appears that in 2030, prioritizing blue hydrogen production has important benefits, compared to a large focus on green hydrogen. These are that hydrogen is available in large quantities for lower costs, and the impact on the carbon price in the ETS is significantly reduced. These findings hold as long as the natural gas price is not too high. If Europe returns to the high scarcity pricing seen at the height of the energy crisis, then green hydrogen is the only economical option.

The work above can be expanded in several important ways, and future research may consider *e.g.*:



(a) No reformers.

(b) No hydrogen production.

(c) Limited reformers.

(d) Unlimited reformers.

Fig. 9. Evolution of total installed European power generation capacity. Reformer cases are with natural gas and electrolyzer cost factors of 1.0.

- **Include endogenous hydrogen demand.** This paper considers optimal deployment of hydrogen production subject to an exogenous hydrogen demand that must strictly be met. However, it is not clear whether the hydrogen demand will grow as forecasted, and this can have a large effect on the results in this paper. A model that considers several decarbonization options in industry and transport will be better able to shed light on what an optimal decarbonization path of Europe would look like.
- **Consider uncertainty in hydrogen demand.** To potential investors in hydrogen production today, the future is highly uncertain. Yet, they will soon have to make decisions about whether to invest in hydrogen production facilities, and the capacity of these. To better reflect the perspective of these investors, the uncertainty of hydrogen demand should be included in the model.
- **Implement CCS in the power sector.** In this work, the only application of CCS is its use in blue hydrogen production. However, CCS can also potentially play an important role in the power sector as well. By implementing CCS in the power sector, one could more easily discern whether natural gas is better used in the power sector in natural gas power plants with CCS, or converted to hydrogen and used as fuel.

CRediT authorship contribution statement

Goran Durakovic: Conceptualization, Data curation, Methodology, Software, Validation, Formal analysis, Investigation, Writing – original draft, Writing – review & editing, Visualization. **Pedro Crespo del Granado:** Methodology, Resources, Writing – review & editing, Supervision, Project administration. **Asgeir Tomasgard:** Methodology, Resources, Writing – review & editing, Supervision, Project administration.

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

The data and code is freely available on Github [34]. The link to the Github has been referenced in the article.

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