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Assessing the implications of hydrogen blending on the European energy system towards 2050

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ABSTRACT

With the aim of reducing carbon emissions and seeking independence from Russian gas in the wake of the conflict in Ukraine, the use of hydrogen in the European Union is expected to rise in the future. In this regard, hydrogen transport via pipeline will become increasingly crucial, either through the utilization of existing natural gas infrastructure or the construction of new dedicated hydrogen pipelines. This study investigates the effects of hydrogen blending in existing pipelines on the European energy system by the year 2050, by introducing hydrogen blending sensitivities to the Global Energy System Model (GENeSYS-MOD). Results indicate that hydrogen demand in Europe is inelastic and limited by its high costs and specific use cases, with hydrogen production increasing by 0.17% for 100%-blending allowed compared to no blending allowed. The availability of hydrogen blending has been found to impact regional hydrogen production and trade, with countries that can utilize existing natural gas pipelines, such as Norway, experiencing an increase in hydrogen and synthetic gas exports from 44.0 TWh up to 105.9 TWh in 2050, as the proportion of blending increases. Although the influence of blending on the overall production and consumption of hydrogen in Europe is minimal, the impacts on the location of production and dependence on imports must be thoroughly evaluated in future planning efforts.

1. Introduction

Given the urgent need to decarbonize the European energy system to meet current climate targets, a reassessment and transformation of the European energy system to effectively address present and future challenges is required [23]. The European Union (EU) is facing increasingly stringent climate targets, including a 55% reduction in Carbon dioxide (CO_2) emissions by 2030 and achieving climate neutrality by 2050 [22]. This calls for a wide expansion of renewable energy sources (RES) to replace current carbon-heavy technologies. The Russian war on Ukraine enhanced these plans further to increase Europe's energy security. As a consequence, the EU has stepped up its efforts to decarbonize its energy sector through the updated “Fit for 55” program, now known as “RePowerEU”, envisioning 1200 GW of RES capacity by 2030. Hydrogen is set to play a vital role as the program further aims to deploy 6 GW of electrolysis capacity to generate renewable hydrogen by 2024 and 40 GW by 2030 [23,21,64]. The EU's hydrogen strategy focuses on natural gas based hydrogen with the application of steam methane reforming and carbon capture and storage (CCS) technology in the short and medium-term but prioritizes non-fossil, renewable hydrogen in the long-term [21,64]. This however, raises relevant questions about the exact implementation and build up of a hydrogen industry in Europe and the viability of utilizing existing transport routes from natural gas for hydrogen trade.

1.1. Hydrogen and its potential for the European energy system

Hydrogen can be produced from a multitude of fossil fuels (e.g. coal, gas), mainly via hydrocarbon reforming methods, such as steam reforming, or hydrocarbon pyrolysis. Its real asset for the energy transition, however, lies in the production from RES. As such, renewable hydrogen can further reduce the reliance on fossil fuels, leading to substantial re-

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ductions in greenhouse gas emissions and a transition towards a more sustainable and low-carbon energy system [1,21]. Renewable hydrogen production processes include less energy intensive and environmentally friendly but slow and low-yielding biological processes as well as comparably faster and higher-yielding thermochemical processes (e.g. gasification) to generate hydrogen from biomass [48]. Most promising and also most widely used and established today are electrolyzers that produce hydrogen by splitting water into oxygen and hydrogen using electricity. Three main electrolysis technologies are notable: alkaline, proton exchange membrane (PEM), and solid oxide electrolysis cells (SOEC). These three technologies differ in multiple aspects, such as costs, use-cases, and maturity. Alkaline electrolysis is already widely available, operational, and has lower capital costs but lacks dynamic operation, which is favorable when operating with intermittent RES [56]. PEM is a less mature technology than alkaline, with higher efficiency and dynamic generation but small-scale applicability and higher costs. The least mature, not yet commercially available technology is SOEC which is set to work at high temperatures (650-1000 °C), have high electrical efficiency, and low material costs [38,56]. The current challenges in improving electrolyzers lie in reducing high capital costs, increasing efficiency, and improving dynamic generation. An expert study by Schmidt et al. [56] finds a shift from alkaline to PEM electrolyzers towards 2030 as likely, due to their dynamic operation with RES and their improvement in cost and lifetime over time.

Hydrogen storage in particular, is seen as a solution to address the seasonal fluctuations in RES such as wind and solar power [64]. A number of simulations have revealed that regions with significant wind energy generation can benefit from the use of hydrogen storage to manage these fluctuations [61,50,4,55]. Hydrogen is commonly stored in either liquid or gaseous form, either in tanks or underground caverns. Liquid storage in tanks is prevalent in small-scale applications, while gaseous storage in underground geological formations is more appropriate for large-scale, long-term storage [37]. Salt caverns have been identified as one of the most viable solutions for large-scale hydrogen storage, due to factors such as safety, cost, capacity, and low losses [25,13]. Caglayan et al. [13] estimate a technical potential of 84.8 PWh_{H_2} in Europe, with at least 7.3 PWh_{H_2} located in onshore formations.

Besides its potential as a flexibility option, driving factors for hydrogen uptake are its use cases in so-called “hard-to-abate” sectors that either lack low-carbon alternative technologies to date or face prohibitive costs, particularly in the industrial and transport sectors. In the industrial sector, hydrogen is already used for refining oil, producing ammonia, methanol, and steel [36]. In the chemical industry, the demand for renewable hydrogen is anticipated to increase as a low-carbon feedstock for producing ammonia and methanol, which have a wide range of industrial applications and could also serve as indirect hydrogen storage solutions [54,41]. Renewable hydrogen also has the potential to be utilized for high-temperature heat production and in the direct reduction of low-carbon steelmaking, given its high calorific value, good thermal conductivity, and high reaction rate [42,51,63]. However, there are still technological barriers that hinder the widespread adoption and large-scale implementation of a hydrogen-based industry. High amounts of low-cost and stable electricity are critical for the economic viability of such an industry [16,67,37]. To overcome these barriers and enable the use of renewable hydrogen, it is crucial that energy and industry transitions are aligned and supported by a framework that takes into account the views of all stakeholders involved [67].

In the transport sector, there has been a rising trend of countries adopting battery electric vehicles (BEVs) to reduce carbon emissions in the sector [3]. This approach, however, is not suitable for fully electrifying freight road, air, and ship transportation [59]. For larger vehicles such as buses and trucks, the use of electric batteries is limited due to the weight of the batteries, creating a demand for alternative technologies. Fuel cell vehicles (FCVs) powered by hydrogen could provide a solution for this issue, as the weight of the energy storage is comparatively low, and hydrogen could be used directly, eliminating the need for a re-electrification process [3,20]. A study by Hainsch [31] finds that hydrogen has a substantial impact on decarbonizing freight transportation in Germany, which can serve as a sign of future trends in Europe. In air transport, hydrogen can be utilized as a direct fuel in the form of liquid hydrogen or converted into synthetic fuels. However, it should be noted that neither of these options is currently economically viable, calling for further research and development [24,34]. As for ship transportation, hydrogen is the most promising substitute as a propulsion fuel, and although there are differing opinions on the best method of storage, hydrogen is considered a promising solution for decarbonizing maritime transportation [45,60].

Despite the growing interest in and optimistic outlook towards the use of hydrogen as an energy carrier in various industries, there are also valid concerns and criticisms to consider. One of the significant drawbacks of renewable hydrogen production is the substantial amounts of land, raw materials, and water required to produce it. Furthermore, it has been argued that hydrogen should only be employed where more efficient options are not available [53]. These factors must be taken into consideration when assessing the potential of hydrogen as a catalyst for energy transformation.

While the potential of renewable hydrogen is widely recognized, its exact scope and role in the European energy system remains subject of discussion. Especially debates about the sites of production as well as the mode of transportation are still ongoing [10,66,40]. Minor amounts of hydrogen might be produced close to the location of its utilization, however, the majority will likely imply a regional separation of production and consumption. Regions with high renewable potentials could prove to be beneficial for the production of renewable hydrogen, whereas regions dominated by industry will likely be the main consumers. Transportation via pipeline will either be done by blending hydrogen into the existing natural gas infrastructure, repurposing parts of the existing natural gas infrastructure, or building new hydrogen-carrying pipelines [2]. However, the extent of utilizing the existing infrastructure and its potential effects on the implementation of hydrogen in the energy system remains a much-discussed topic to be investigated in this paper.

Following the introduction, Sections 2 and 3 give an overview of the applied model, data, and scenario assumptions. Thereafter, Section 4 explores the results of the model application and possible chances and barriers for Europe’s low-carbon energy transition. Section 5 discusses implications of the model results, followed by a brief overview of model limitations and a research outlook. The paper is summarized and concluded in Section 6.

1.2. Related literature

In 2022, a consortium comprised of European gas transmission companies released an update to the first European Hydrogen Backbone from 2020, a concept for European hydrogen transport infrastructure that estimates a network covering around 50,000 km in 2040 with 60% built on existing natural gas infrastructure and 40% new dedicated hydrogen pipelines. Additionally, the backbone extends the transport of hydrogen via pipeline by transporting hydrogen derivatives via ship. This includes the transport of ammonia as well as (LOHCs) [29,30]. A study by Neumann et al. [46], using an open-source capacity expansion model of the European energy system (PyPSA-Eur-Sec) investigates trade-offs between new electricity transmission lines and a hydrogen network. It shows that in net-zero emission scenarios, a European hydrogen network offers significant cost benefits. The hydrogen network can lower system costs by up to 3.4%, particularly when there is no need for power grid expansion. Approximately 64% to 69% of the hydrogen network utilizes retrofitted gas network pipelines. As power grid expansion remains more cost-effective, the most substantial savings are achieved by integrating both power grid expansion and the hydrogen network.

While transmission of hydrogen by pipeline is generally the cheaper option for distances below 1,500 km according to IEA [36] for longer distances, especially overseas, Ammonia and LOHCs are much easier to transport. However, they often cannot be used as final products and require a further conversion step before final consumption [7,47,52]. This entails extra energy and cost, which must be balanced against the lower transport costs. Brändle et al. [10] come to similar results regarding the mode of transportation. In their work, they analyze the long-term supply and production costs of low-carbon hydrogen through cost-minimizing linear optimization. The results suggest that hydrogen transportation in ships is cost-efficient for distances over 2000 km compared to pipeline transport assuming high costs for new hydrogen pipelines. However, when assuming lower construction and operating costs of dedicated hydrogen pipelines, this distance increases to 7000 km. Overall, they find that retrofitting natural gas pipelines results in the least cost solution, increasing the feasibility of hydrogen trade. Consequently, hydrogen trade would be mostly concentrated regionally.

Using existing natural gas infrastructure presents several advantages, including availability, social acceptance, and lower costs for retrofitting compared to the construction of new pipelines [37,14]. Transmission system operators assume the costs for retrofitting to be at around 10-15% of new constructions, making it an attractive option to transport hydrogen and re-use existing pipeline infrastructure at the same time [57]. In the short to medium term, blending renewable hydrogen into the existing gas network helps make natural gas flows and its final consumption less emission-intensive. Furthermore, it is a solution that can be implemented quite quickly compared to the alternatives that require entirely new constructions. Zhou et al. [66] argue that blending hydrogen in the gas network can help absorb abundant electricity and act as a storage. They find that the more hydrogen is blended, the less electricity is curtailed. Sorgulu and Dincer [58] further calculated that CO_2 emissions decrease by adding hydrogen to natural gas networks.

There are, however, caveats related to the transport of hydrogen blend via pipeline. A study by Kotek et al. [40] examines the viability and cost of various pipeline transportation methods for hydrogen, including blending, repurposing, and dedicated pipelines. According to the study, the majority of hydrogen infrastructure will consist of repurposed gas pipelines to accommodate higher volumes of hydrogen transport. The study finds that blending hydrogen into the natural gas grid will mostly be viable for lower volumes of hydrogen transport and names the presence of natural gas flows as a relevant constraint. Hydrogen blend into gas pipelines decreases the transportable energy content [26]. To be fed into the transmission system, hydrogen must be compressed to the operating pressure of the network. To maintain pressure despite loss of flow in the pipeline, more and higher-power compressors are required along the pipeline in comparison to natural gas [29,57]. As countries (in the EU) have different norms and legislation on the maximum level of hydrogen allowed (by volume), Vidas et al. [62] highlight the need for risk-assessment and joint planning across regions and borders. Increasing the share of hydrogen in existing gas pipelines causes higher costs for applications, re-compression, and retrofitting of the pipelines [8,39,65].

A review by Mahajan et al. [44] mentions additional techno-economic problems in current hydrogen blending projects. These include the need for new safety standards as risks of leakages and safety concerns increase as well as risks of hydrogen induced corrosion and embrittlement over long term usage. Erdener et al. [19] expand on the topic by addressing the need for consideration of the network's material composition, topology, and end-users in future research to assess potential problems and highlight the need for operations experience with hydrogen blending. Furthermore, Bard et al. [8] and Erdener et al. [19] warn of lock-in effects of hydrogen blending infrastructure potentially delaying transitional efforts and significant price impacts for end-users despite the general agreement that hydrogen should primarily be used for specifically targeted end-use instead of area-wide adaption.

1.3. Motivation, aim, and novelty

Despite the numerous studies that have investigated the techno-economic aspects of hydrogen blending and its effects on the distribution grid and consumers (e.g. Giehl et al. [28]), there is a lack of research on the impacts of hydrogen blending on the European energy system and international trade and transmission. Allowing hydrogen in existing natural gas networks can potentially affect the location of hydrogen production and international trade. This is an area that requires further investigation in order to gain a comprehensive understanding of the full range of effects of hydrogen blending on the energy sector.

This paper aims to compare the impacts of injecting various percentages of hydrogen into the existing natural gas pipeline transmission system, focusing on the implications for the European energy system. The study builds on low-carbon transition pathways for Europe developed in the Horizon 2020 project *Open ENTRANCE* [6,32]. By introducing sensitivities for hydrogen blending in the Global Energy System Model (GENeSYS-MOD), this paper explores how hydrogen blending options affect production, transport options, and regional localization of hydrogen generation in Europe. In addition, the study includes a trade sensitivity to better understand the effects of a decreased trade dependence on hydrogen imports from countries outside of Europe. The study contributes to the current discussion around hydrogen utilization and transport by generating new insights to help guide the conceptualization of a European hydrogen network best fit for its future purpose. The focus of this paper is not on the techno-economic feasibility of injecting different shares of hydrogen into existing gas pipelines, but the overall effects it would have on the energy system in Europe.

2. Methodology

The method employed in this study makes use of GENeSYS-MOD to analyze the implications of hydrogen blending. In order to achieve that, modifications to the model were made, improving the representation of the gas transmission network and introducing the ability to blend hydrogen into the existing gas infrastructure.

2.1. Model description

GENeSYS-MOD is a linear open source energy system model which is tailored to analyze low-carbon energy transition pathways considering all energy sectors: electricity, buildings, industry, and transportation. First published by Löffler et al. [43], it extends the Open Source Energy Modelling System (OSeMOSYS) framework and was expanded by numerous features and functionalities since then. Its main strength lies in the simultaneous optimization of capacity expansion, energy generation, and dispatch of all energy sectors, which leads to an endogenous optimization of electricity and hydrogen demand considering interactions between all energy sectors. The models focus on sector coupling, combined with the integrated approach to calculating long time horizon scenarios while still maintaining sufficient temporal degree of detail, makes it possible to gain valuable insights into the role of hydrogen integration in the European energy system up to 2050. This is in contrast to many other models which often focus on the operational aspects of the energy system, favoring inner-yearly time resolution over long-term planning horizons [9,15,49]. The perfect foresight characteristic of GENeSYS-MOD expands on this aspect and minimizes the risk of stranded assets and provides well-founded expansion and investment pathways for technologies and infrastructure. Furthermore, hydrogen demand will be optimized endogenously but can also be exogenously given, allowing a detailed inclusion of hydrogen demands for different sectors and applications. Fig. 1 illustrates a simplified version of model inputs, components, and outputs. Climate policies and targets, regional particularities, and technological diversity are easy to implement, allowing flexible analyses and easy adoption by other users and research

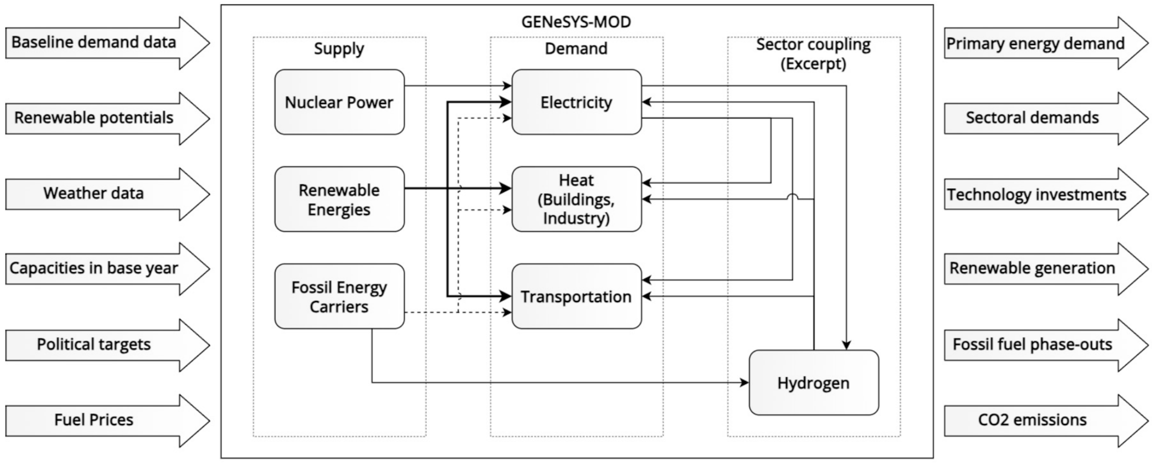

Fig. 1. Stylized graph of model inputs and outputs of GENeSYS-MOD. Source: Own illustration.

groups. Therefore, the framework and data used are fully open source to enable validation and reproducibility..[1]

For this work, a model setup applied in the Horizon 2020 project *Open ENTRANCE* is used in which low-carbon transition pathways for Europe were developed as part of an open modeling platform targeted towards policy and decision makers, stakeholders, and the research community. The four pathways represent three very ambitious scenarios aimed at limiting global warming to a maximum of 1.5 °C and one slightly less ambitious, yet still compatible with a 2 °C climate target, taking into account different developments across the political, societal, and technological dimensions [6,32].

The *Gradual Development* scenario has been chosen for further use in this study, representing a moderate mixture of all three dimensions. Europe is disaggregated into 30 regions (mainland EU-25, Norway, Switzerland, UK, Turkey, and an aggregated Balkan region) and a pathway from 2018 to 2050 is calculated in 5-year steps. 2018 is used as a reference year for calibration purposes with generation, capacities, and emissions adjusted to reflect the historic values. To address the question of how different shares of hydrogen in natural gas pipelines affect hydrogen production and transportation infrastructure, various model runs allowing different shares are computed and the results are compared.

2.2. *Model functionality regarding gas transmission infrastructure and hydrogen blending*

Extending the European model version 3.1, some improvements were made to the model so that hydrogen is represented in a more accurate way in the energy system, specifically regarding its trade across regions.

So far, the only option to trade hydrogen in the model has been via trucks or in newly built dedicated hydrogen pipelines. However, in reality, hydrogen can also be transported through existing gas infrastructure by blending it with natural gas. Using existing capacities for hydrogen transport can save initial capital costs that would be created by building new dedicated pipelines or re-purposing old gas pipelines. With this, the trade of hydrogen could become more attractive for the model. First, the natural gas infrastructure data for the model was updated according to ENTSO-G [18] to ensure natural gas pipelines were fully implemented and available to the model. In order to achieve the hydrogen blending within existing natural gas infrastructure, a new fuel *H2_blend* was added to the model formulation. This fuel can only be produced from hydrogen, transported through natural gas pipelines, and then converted back into hydrogen for use.

Furthermore, a parameter called *switch_dedicated _hydrogen_tradecapacity* was introduced. This parameter limits the amount of hydrogen that can be blended into a natural gas pipeline. The switch is implemented in the following constraint (see Equation (1)) that regulates how much hydrogen blend can be imported in relation to the imported methane in a specific country per time slice.

$$Import_{(y,l,H2\_blend,rr,r)} \leq (switch\_dedicated\_hydrogen\_tradecapacity / (3.8 - switch\_dedicated\_hydrogen\_tradecapacity)) * Import_{(y,l,Methane,rr,r)}) \quad (1)$$

Furthermore, since the energy density of the blended hydrogen is lower than the energy density of natural gas, this also had to be accounted for. The formulation of the trade capacity in the model only considers energy as a limit, whereas in reality, the volume of the pipeline restricts the quantity that can be transported. In order to account for that the factor by which the energy density differs (3.8) is multiplied on top of the amount of hydrogen that is blended into the natural gas pipeline. The focus of this paper is on the transmission grid in Europe. As the hydrogen blend in the natural gas pipeline would effect the distribution networks and ultimately consumer appliances, the model "separates" hydrogen from methane after transport, resulting in the consumption of pure hydrogen.

Another improvement that was made is the introduction of dedicated liquifier and gasifier technologies. This improved on the previous model formulation, where one single technology existed that could liquefy or gasify both natural gas and hydrogen interchangeably. That meant the costs for the processes would be the same for both natural gas and hydrogen. In reality however, the liquefaction and gasification plants for each fuel differ substantially. In order to account for the differences, two new technologies were introduced: a *X_Liquifier_H2* and a *X_Gasifier_H2*.

3. Scenario assumptions

This section will briefly introduce the base scenario used in this study. Following, the implementation of the hydrogen blending sensitivities and trade sensitivities is presented.

[1] See Appendix A or visit the official public GitLab page (https://git.tu-berlin.de/genesysmod/genesys-mod-public) for further information on GENeSYS-MOD.

Table 1
Main assumptions for capital costs, fixed costs, and efficiency of electrolyzers in the Gradual development scenario.

Electrolyzers								
Year	2018	2020	2025	2030	2035	2040	2045	2050
Capital Costs (M€/GW)	800.0	685.0	580.0	442.9	416.0	396.6	373.8	362.1
Fixed Costs (M€/GW)	24.0	20.6	15.0	10.9	9.8	8.9	8.0	7.4
Efficiency (%)	64.0	73.5	77.6	79.0	79.9	80.5	81.1	81.6

3.1. The gradual development scenario

The scenario chosen for this analysis was the Gradual Development scenario, one of four scenarios developed in the Horizon 2020 project Open ENTRANCE [32]. It distinguishes itself by reaching its targets through equally including societal, industrial, and political action. Its costs and efficiencies are moderately optimistic, newer technologies are not implemented and hydrogen trade is only considered within the 30 model regions. Out of the four scenarios, the first three scenarios (Societal Commitment, Directed Transition, Techno-Friendly) aim to reach 1.5 °C, resulting in greenhouse gas neutrality around 2045, while the Gradual Development Scenario aims for a less ambitious 2 °C.[2] Society is slightly less involved compared to the Societal Commitment Scenario and the carbon price is lower than in the other three scenarios. The Gradual Development scenario is used as the base scenario for this study as it combines aspects of all the other three scenarios, while still aiming for an ambitious 2 °C goal. It is the most balanced in its ambitions helping the model to easily include new hydrogen related constraints and limitations to calculate blending sensitivities.
Table 1 gives an overview of the main assumptions for electrolyzers used in this study from the Gradual development Scenario. Capital costs for electrolyzers gradually reduce from an initial 800.0 M€/GW in 2018 to 362.1 M€/GW by 2050 as do the assumed fixed costs from 24.0 M€/GW in 2018 to 7.4 M€/GW in 2050. As electrolyzer technologies are expected to further develop over the modelled period, efficiency rises from 64.0% in 2018 to 81.6% in 2050. These projections are in line with studies by IRENA [38] and Schmidt et al. [56], projecting similar future developments.

These assumptions are, however, subject to uncertainty and greatly influence the modelling outcomes. To ensure transparency and robustness of model results, a sensitivity analysis was conducted to evaluate the changes in model results when input parameters for capital costs and efficiency of electrolyzers are varied (see Section 4.2.4 and Appendix D).

3.2. Hydrogen blending sensitivities

In order to investigate the use of existing gas infrastructures for the transport of hydrogen within the model, the share of hydrogen allowed in the existing natural gas pipelines is adjusted gradually. To do this, the model is allowed to add hydrogen (in volume) to the gas network in 5% increments utilizing the *switch_dedicated_hydrogen_tradecapacity* for each model run from 2018-2050. A model run is performed for each possible ratio from 0% (no hydrogen blending allowed) to 100% (hydrogen can be freely distributed within existing gas pipelines), resulting in a total of 21 model runs.

3.3. Trade sensitivities

The growing interest in hydrogen as a clean energy carrier has led to a focus on its production and distribution, with many countries considering import options to meet their demand. Importing hydrogen from countries with high renewable energy potential outside of Europe such as Turkey presents both opportunities and challenges for energy security in Europe. On one hand, it could create new energy import dependencies from outside of Europe, while on the other, it could diversify the supply chain and reduce reliance on a single source. Given the current discussions around energy dependencies following the Russian war on Ukraine, the potential impact of trade limitations on energy imports is an important area of research. This paper aims to analyze the impact of limiting Turkey's hydrogen and synthetic methane exports on the production and trade of hydrogen in Europe. Using a model run that simulates such trade limitations, the paper aims to provide insights into the implications for the hydrogen industry, trade, and energy security in Europe.

4. Results

This section presents the general results for the Gradual Development scenario, followed by pan-European and regional effects of hydrogen blending on the European Energy System. In addition, the model results for trade restrictions and the results of a sensitivity analysis are presented.

4.1. Developments of the European energy system in the gradual development scenario

As can be seen on the left in Fig. 2, the electricity system in Europe is significantly decarbonized from 2018 until 2050. This is mainly driven by the increase in power generation from solar and wind, supplying more than 85% of power in 2050. Furthermore, hydropower remains a relevant power source with nuclear power also constituting a fair amount of power generation. The rapid decarbonization causes a coal phase-out by 2040 and only marginal amounts of natural gas remain within the energy mix by 2045. Reaching 2050, the electricity system will be fully decarbonized. On the consumption side, electrolysis becomes one of the most important drivers, accounting for over 35% or 3,450.0 TWh of total electricity consumption by 2050 in Europe.

The right graph in Fig. 2 shows the hydrogen generation and consumption. By 2050, most hydrogen will be used as feedstock in industry, accounting for 56% of the total consumption of 2,760.0 TWh (here shown as final demand for hydrogen, due to its non-energetic use case). Another 26% is used in the transport sector, especially in freight transport and aviation. While around 10% of hydrogen will be used for heating in the buildings sector (with the most common use being combined heat and power plants (CHPs) for district heating), only 1% is directly used for process heating in industry. Instead, a substantial increase in methanation, the production of synthetic methane using hydrogen (in the following referred to as syn-Gas), can be observed in the later years, increasing to around 200.0 TWh in 2050, mostly being used in industry as a replacement for fossil gas in process heat applications. As for the generation side, hydrogen will only be produced by means of electrolysis throughout the whole model period. For this reason, hydrogen storage plays an important role in this transition, providing the majority of seasonal flexibility across the different sectors.

Fig. 3 shows regional results for various key indicators for the Gradual development Scenario in 2050. The top left image shows the hydrogen generation in Europe by 2050. The main producer of hydrogen in

[2] For more detailed descriptions of the scenarios, consult Appendix B & Auer et al. [6].

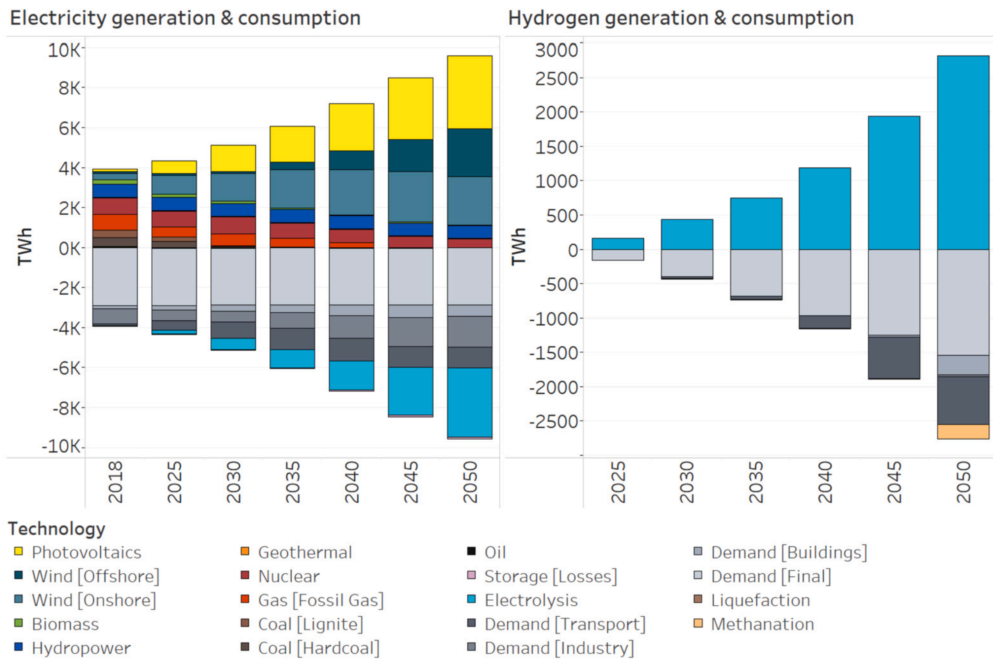

Fig. 2. Results for electricity generation and consumption (left) and hydrogen generation and consumption (right) in the Gradual Development pathway. Generation is displayed in positive numbers, consumption in negative.Source: Own illustration.

Europe in 2050 will be Turkey with 470.0 TWh according to model results from the Gradual Development Scenario. Spain and France can be identified as the next biggest producers of hydrogen with 359.0 TWh and 298.0 TWh respectively. Wind electricity generation (top centre image) in 2050 is most prominent in countries with the highest renewable potential and energy demand such as Germany generating 842.2 TWh, the United Kingdom generating 704.0 TWh, and France generating 543.4 TWh. Solar electricity generation in 2050 (top right image) is most prominent in countries with high solar potential, particularly Turkey producing 819.9 TWh from solar and Spain producing 471.6 TWh. In general, countries with high electricity generation from wind and solar energy also have a high production of hydrogen.

Electricity demand in 2050 (bottom left image) is highest in the most populous countries with large economies, namely Germany, France, Turkey, UK, and Italy. Regarding hydrogen and syn-gas Exports (bottom centre image), Turkey and Spain lead the other countries by leveraging their renewable potential for the production and export of hydrogen, exporting 250.5 TWh and 213.2 TWh respectively. As can be seen in the bottom right image, Germany imports the most hydrogen and syngas with 281.1 TWh in 2050. It is important to note that countries like Bulgaria exhibit high import and export numbers as the hydrogen produced in Turkey is transported through them.

4.2. *Sensitivity analysis on gas transmission infrastructure*

Following the description of the results for the Open ENTRANCE Gradual Development scenario, the results for hydrogen blending in the existing natural gas infrastructure and its impacts on the European Energy System will be presented.

4.2.1. *Pan-European effects*

The overall energy production and consumption within the EU exhibits no distinct changes across different shares of hydrogen allowed in existing gas pipelines (see Fig. 4).

This potentially counter-intuitive result can be explained by a very inelastic demand in hydrogen as a result of its specific use cases in difficult to decarbonize sectors and its higher costs and lower efficiency compared to other, usually electric, technologies. In many cases, direct electrification still offers a more efficient and cheap solution compared to the generation of renewable hydrogen. Despite no additional costs to increase the share of hydrogen in the existing natural gas infrastructure, hydrogen does not become significantly more economically competitive. As a result, Europe as a whole consumes similar amounts of hydrogen across all sensitivities. The production of hydrogen only increases by 0.17% for 100%-blending allowed compared to no blending allowed. Overall system costs do decrease, however, with hydrogen blending as a cheaper alternative to dedicated hydrogen pipelines. The cost reduction is most pronounced at 100%-blending, where system costs decrease by 0.0056% compared to the case when no blending is allowed. In contrast, the next section will demonstrate that the presence of hydrogen pipeline transportation has a significantly greater impact on regional production patterns and distribution.

4.2.2. *Regional effects*

While the overall production and demand of hydrogen within the EU barely change over the different sensitivities, significant differences can be found at the national level as shown in Fig. 5 for the sensitivities of 0%-blending (no blending allowed), 20%-blending, 80%-blending, and 100%-blending (full usage of pipelines for hydrogen transport) from left to right. With increasing shares of hydrogen allowed in existing pipelines, Norway's hydrogen and syn-gas net exports in 2050 rise from 44.0 TWh at 0%-blending to 105.9 TWh at 100%-blending.[3] As currently one of the major exporters of natural gas in Europe, Norway can leverage the existing pipelines to export its hydrogen, making it the fourth biggest exporter of hydrogen after Turkey, Spain, and Denmark at 100%-blending. Turkey and Spain remain the most important exporters of hydrogen across all sensitivities due to their vast renewable potential. Turkey exports the most hydrogen using dedicated hydrogen pipelines in all sensitivities. The model's techno-economic perspective favors pipeline transport over longer distances, as it becomes a more cost-effective alternative to electricity transmission. In the base case (0%-blending), Turkey produces and exports more than 250.0 TWh of hydrogen. When the share of hydrogen allowed in existing gas pipelines rises, however, Turkey exhibits a reduction in exports to 237.8 TWh at 100%-blending as other countries located much closer to customers

[3] For further information on results see Appendix C.

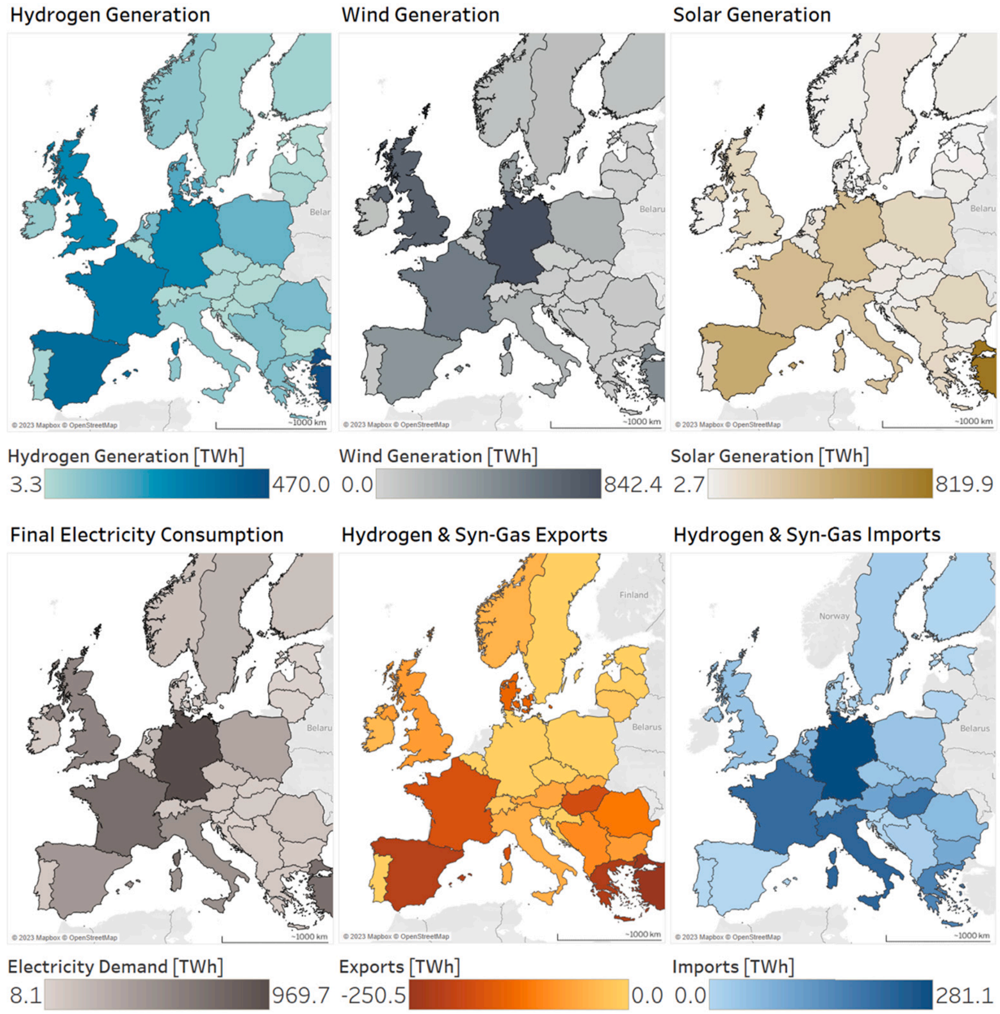

Fig. 3. Geographic distribution of hydrogen generation, electricity generation from wind and solar, final electricity consumption, hydrogen and syn-gas exports and imports in 2050 with no blending. Source: Own illustration.

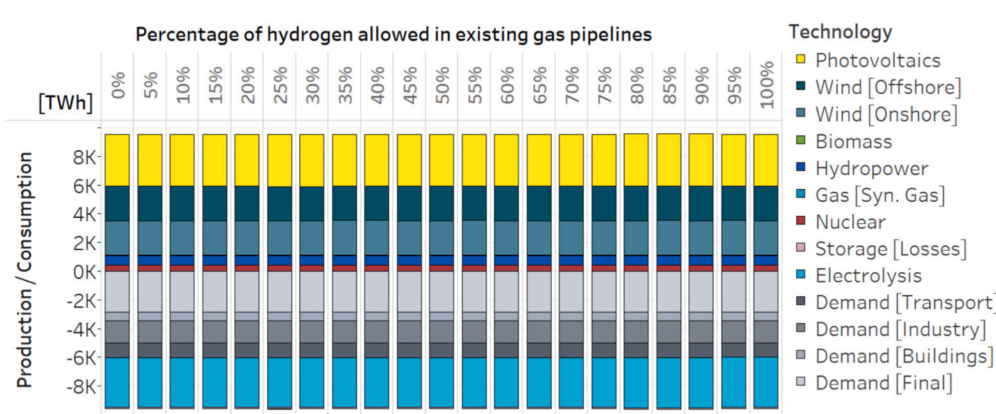

Fig. 4. Change in electricity generation and consumption in 2050. Source: Own illustration.

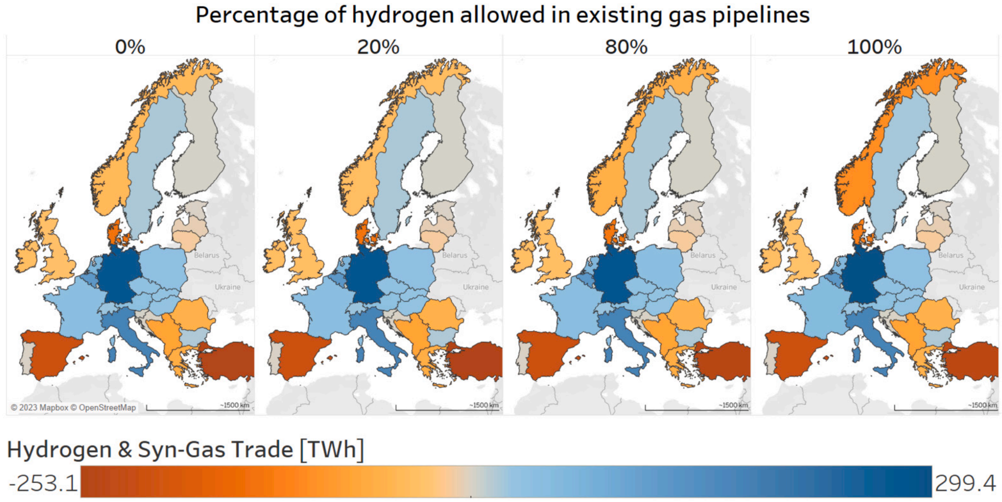

Fig. 5. Net Trade Hydrogen & Syn-Gas for selected shares in 2050. Source: Own illustration.

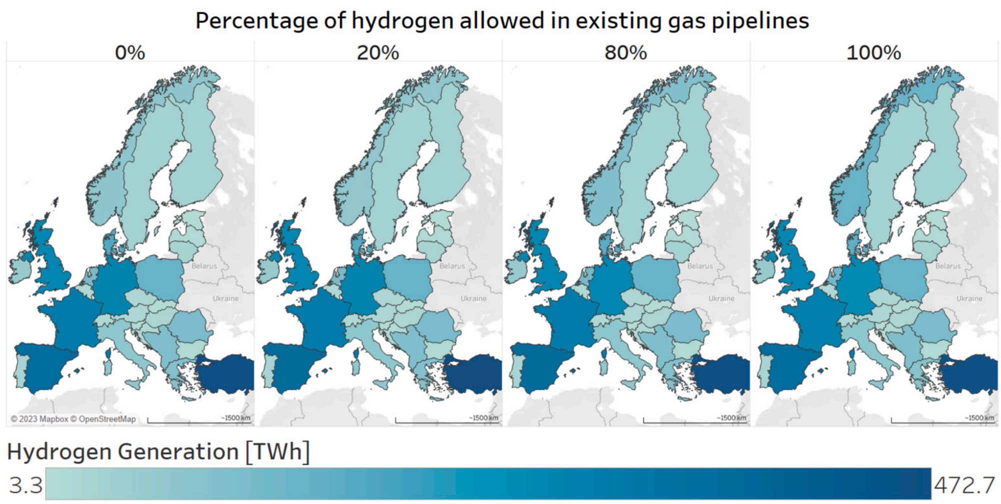

Fig. 6. Hydrogen Generation for selected blending shares in 2050. Source: Own illustration.

in central Europe (e.g. Denmark and Norway) can use their existing pipelines to export more hydrogen. As Spain is situated closer to the main hydrogen importing countries it exhibits a very subtle reduction from 213.0 TWh at 0%-blending to 211.9 TWh at 100%-blending.

Germany and Italy are the largest net importers across Europe. Particularly Germany exhibits a steep increase in imports from 277.3 TWh at 0% to 299.4 TWh at 100% of hydrogen allowed in existing gas pipelines. This is a result of Norway's increased exports of hydrogen to Germany via the already existing gas grid, which sees large pipeline capacities between the two countries.

The hydrogen generation in Europe, shown in Fig. 6, changes congruently with exporting and importing numbers. Hydrogen generation increases the most in Norway, it sharply rises from 71.9 TWh at 0%-blending to 135.3 TWh at 100%. The main hydrogen producers at 0%-blending are Turkey with 470.0 TWh, Spain with 359.0 TWh, and France with 298.0 TWh.

Spain's generation remains steady while Turkeys production slightly decreases to 456.0 TWh with rising shares of blending as export shifts to Norway. Germany's hydrogen production also decreases with rising amounts of blending as more hydrogen is imported from Norway using existing natural gas pipelines.

Fig. 7 reinforces previous findings and shows the impact of the different percentages of hydrogen allowed in existing gas pipelines on the the main hydrogen producing and trading countries in Europe. Germany, both a producer and importer, reduces production and increases imports with rising blending shares as hydrogen is preferably produced in Norway which then trades the hydrogen to Germany via natural gas pipelines. Spain's generation and trade remain stable at all blending shares. Norway increases its hydrogen production and trade most with rising shares, reaching its peak at 100% of the gas infrastructure being usable for hydrogen trading. Turkey exhibits a contrasting outcome. The integration of hydrogen blending leads to a reduction in both hydrogen production and trade.

4.2.3. Trade restrictions

Fig. 8 shows the impact of a fully self-sustained Europe (reducing the import dependency of Turkey) on the trade patterns in Europe. The sensitivity results reveal that exporting countries like Spain and, particularly at high blending shares, Norway, experience a significant rise in hydrogen exports compared to the results obtained without any trade restrictions. In the absence of Turkey's substantial generation contribution, there is a need for increased domestic hydrogen production and trade to meet the hydrogen demand in Europe.

Spain becomes the largest exporter, with net-exports increasing from 213.0 TWh to 222.0 TWh for 0%-blending and from 211.0 TWh to 219.2 TWh at 100%-blending allowed. Norway's net trade also increases for all blending shares in the sensitivity scenario, going up from 66.8 TWh to 81.6 TWh compared to the base scenario at 100%-blending in 2050. Turkey's net-trade is much lower due to the model constraints and fur-

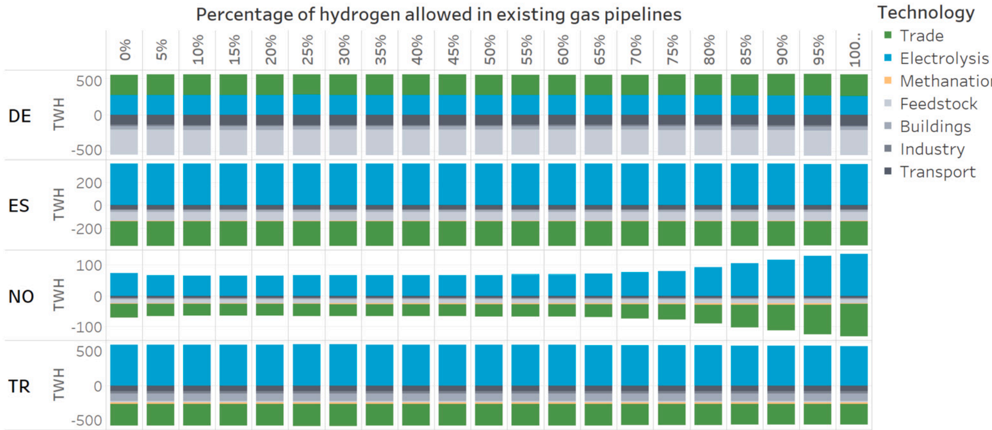

Fig. 7. Hydrogen generation and use at country-level for select countries in 2050. Source: Own illustration.

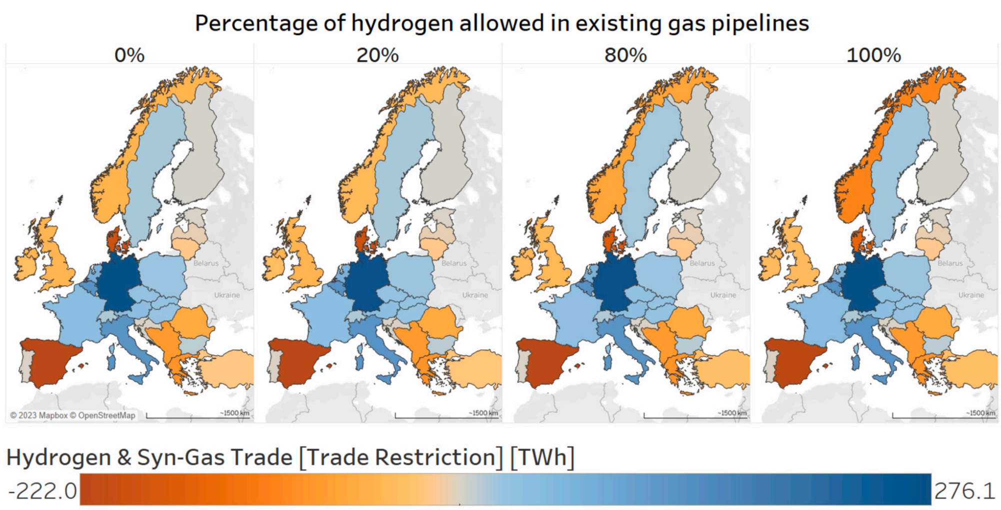

Fig. 8. Net Trade Hydrogen & Syn-Gas with Trade Restriction for selected shares in 2050. Source: Own illustration.

ther decreases with rising blending shares.
Overall system costs decrease by 0.02% from no blending to 100%-blending. Compared to the model runs with no trade restrictions, hydrogen production costs increase by 1.2% at 100%-blending while the overall system costs only increase by 0.0264% for no blending and 0.0216% at 100%-blending, effectively trading a cost optimal energy system for a decrease in dependence on hydrogen imports from outside the EU.

4.2.4. Sensitivity analysis

In order to assess the robustness of the model, particularly with regard to hydrogen, sensitivities were calculated for the efficiency and capital costs of electrolyzers, based on the application in Hainsch [31]. Table 2 shows the variables for which sensitivities have been calculated, their respective range and the applied factor. Maximum and minimum values for the parameters consist of the parameter's default value multiplied or divided by two. In total, 100 model runs are calculated per sensitivity, linearly distributed between the factors 0.5 and 2. The sensitivities start taking effect in 2035.

For each sensitivity 100 model runs were calculated for the base model without blending (0%) and blending shares of 20%, 80%, and 100% to cover the broad spectrum of blending shares, resulting in a total of 800 model runs. Fig. 9 shows the results for the different blending shares for both sensitivities.

As expected, the model exhibits an increase in hydrogen production across all blending shares both with an increase in the efficiency of the electrolyzers and with a reduction in capital costs (factor of 0.5). Inversely, a decrease in efficiency and an increase in capital costs lead to a decrease in hydrogen production in all scenarios (factor 2). The sensitivities' effect on hydrogen blend production generates additional insights. For the efficiency sensitivity, blending shares at 20% and 80% exhibit an increase in hydrogen blend production with higher efficiency. For 100%-blending, hydrogen blend production is significantly higher than in the lower blends (spanning between 170-230 TWh in 2050) but there is also a more uneven and mixed distribution of sensitivity results. This is likely the result of an increase in regional production, due to higher efficiencies, causing a reduction in trade. This effect is much more pronounced for the hydrogen blend production under the capital cost sensitivity. The span of hydrogen blend production by 2050 is much wider, ranging between 130-250 TWh and hydrogen blend production is reduced as capital costs of hydrogen decrease. As transport costs remain the same, cheaper costs for electrolyzers lead to a significant uptake in regional production. These findings highlight that lower costs of electrolyzers favour regional production while higher costs lead to more trade of hydrogen blend and the usage of existing infrastructure to reduce overall costs.

Additional figures and information on the regional distribution of exports and imports of hydrogen blend can be found in Appendix D.

5. Discussion of model results and limitations

The main aim of this study is to examine the impact of hydrogen blending on the European energy system. The results of the study show that hydrogen blending has little effect on the overall demand of hy-

Table 2
Analyzed sensitivities, corresponding model parameters, and intervals of values for the year 2035.

Sensitivity	Parameter	Range			Factor
		Min	Default	Max	
Efficiency	Efficiency of electrolyzer	66.5%	79.0%	88.8%	2[a]
Capital Costs	Capital Costs for electrolyzer	208.0 M€/GW	416.0 M€/GW	832.0 M€/GW	2

[a] The factor *2* in the case of efficiency describes how the losses due to efficiency are changed.
Default efficiency: $79\% = \frac{1}{1.2518} = \frac{1}{1+0.2518}$
Max efficiency: $88.8\% = \frac{1}{1.129} = \frac{1}{1+0.129} = \frac{1}{1+0.2518/2}$
Min efficiency: $66.5\% = \frac{1}{1.5036} = \frac{1}{1+0.5036} = \frac{1}{1+0.2518*2}$

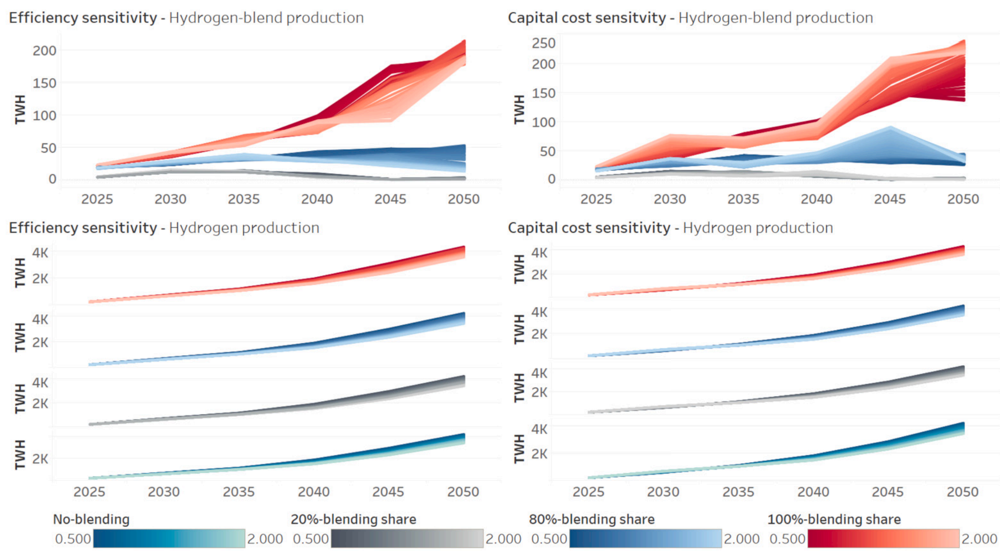

Fig. 9. Hydrogen Sensitivities for electrolyzer efficiency and capital costs. The color range represents the factor of the respective sensitivity. Source: Own illustration.

drogen by 2050. This suggests that the production and consumption of hydrogen are not limited by transportation options but rather high production costs and more efficient, less cost-intensive alternative solutions in many use cases. Despite the ability to utilize existing natural gas pipelines at no additional cost for hydrogen transport in our model setup, the net production of hydrogen remains largely unchanged in 2050. This is because hydrogen is rarely the most cost-effective and sensible option, and is instead only used where direct electrification is difficult to achieve, or as seasonal flexibility option. In these cases, the demand for hydrogen is very inflexible. This is an interesting find, as it shows a clear “floor” for hydrogen demand in these challenging applications, but no further adoption of hydrogen as an energy carrier across a larger cost range due to it’s lower energy efficiency.

Contrary to the negligible effects on overall demand in Europe, the ability to blend hydrogen into the existing natural gas pipelines strongly affects the regional distribution of hydrogen production and trade. Without blending, countries with abundant unused renewable energy resources, such as Spain and Turkey are the main producers of hydrogen. As the share of hydrogen allowed in existing pipelines increases, production relocates to countries closer to central Europe. Norway experiences the largest increase in hydrogen generation, but also Germany and other countries see an increase in generation as natural gas pipelines can now be used for hydrogen trading. Even with decreased production, Spain remains the largest exporter of hydrogen, while Norway grows to be the second largest. As the production’s localization switches to central Europe, Turkey experiences the largest decrease in production and exports, losing significance as the largest exporter of synthetic methane. France, Germany, and Italy are the biggest importers of hydrogen and syn-gas in Europe in 2050. However, while German imports rise steeply with more hydrogen being allowed in existing pipelines, France’s imports decline due to lower exports from Spain.

These findings align with the European Hydrogen Backbone, a study conducted in collaboration with multiple infrastructure operators in Europe, that focuses on the establishment of distinct hydrogen corridors and supply routes throughout various regions in Europe until the year 2040 [30]. It identifies 5 main primary hydrogen routes: a Southwest corridor originating from Spain and Portugal, a North Sea corridor originating from Norway, a Nordic and Baltic corridor including countries such as Sweden an Finland and the Eastern European corridor all facilitating hydrogen transportation to central Europe. Contrary to our study, it also includes a North Africa-Italy corridor to facilitate the import of hydrogen from the African continent. Our study demonstrates that the composition and significance of these corridors may vary depending on the proportion of hydrogen permitted for injection into the grid. Notably, our findings highlight the substantial impact of Turkey on the model results, exhibiting the most significant variations with different blending shares. Consequently, these variations have the potential to greatly influence the role and importance of the Eastern European corridor.

The impact of hydrogen blending on the overall production and demand of hydrogen may not be significant, but the location of production can have profound implications for the European energy system. Importing hydrogen from countries such as Turkey can potentially create a new dependency on energy imports for the EU. This underlines the importance of careful planning in establishing hydrogen “backbones” due to the potential path dependencies. To enhance energy security, the EU should reduce its reliance on energy imports, thereby mitigating vulnerabilities to supply disruptions, price fluctuations, and geopolitical tensions. Achieving this objective entails increasing the domestic production of renewable energy, improving energy efficiency, and promoting energy diversification through the utilization of multiple sources and supply routes to meet the increased demand. Reducing dependence on energy imports not only enhances energy security but also yields positive economic implications. By decreasing reliance on imports, countries can stimulate job creation, foster economic growth, and attract more investment in the European energy sector. Conversely, countries such as Turkey have substantial renewable energy potential. By leveraging these regional strengths, the EU can tap into lower-cost hydrogen production. This cost reduction has the potential to make hydrogen more competitive in the energy market and accelerate its widespread adoption across various sectors.

In general, hydrogen trade within the EU will be essential to meet hydrogen demand. An increase in trade within the EU via the existing gas infrastructure as well as via new pipelines is necessary and will lead to more and new bilateral trade agreements within the EU and other exporting countries. Hydrogen trade can serve as a platform for fostering economic partnerships and developing mutually beneficial relationships with energy-exporting countries. The results of the sensitivity analysis further show that with higher capital costs for electrolyzers, the existing gas-infrastructure will play a more accentuated role. Striking a balance between trade relations and energy independence requires a comprehensive evaluation of risks and the implementation of appropriate measures by all European states involved. It is crucial to approach future hydrogen plans collaboratively, conducting thorough analyses and making collective decisions to safeguard the EU's energy security and long-term sustainability.

5.1. Limitations and research outlook

The following section highlights some limitations in our research set-up and the results obtained in this study and provides guidance for future research on hydrogen trade using GENeSYS-MOD. It is important to note that the model solely focuses on the transmission network of the gas grid for hydrogen transportation between countries via pipelines. Consequently, the model does not account for the distribution grid or regional hydrogen transport within individual countries. As a result, conclusions drawn from the research can only be applied at a broader European level, not taking into account potential variations and influences that may exist at a local or national level. This highlights the need for further research when interpreting the results in a more granular context. Additionally, the analysis does not incorporate the global trade of hydrogen. Regions endowed with substantial potential for renewable hydrogen production could potentially export their hydrogen to Europe, introducing competitive pricing and potentially altering the dynamics of hydrogen production and trade within Europe. While this was not in the scope of our study, future research should explore the potential impact of global hydrogen trade on European hydrogen production, trade, and utilization.

It is important to acknowledge that the current model setup allows for hydrogen to be blended into the gas network up to 100% without additional investments into technical devices such as valves and compressors. However, in reality, this is only possible up to around 10% [8]. Considering costs related to retrofitting might decrease the economic viability of some of the transport routes that are currently chosen by the model.

Additional points to consider are the various challenges such as the combustion behavior of hydrogen, which can affect the materials used in the used infrastructure. The key issues include effects on end-use appliances and safety, impact on the longevity of existing natural gas pipelines, changes in pipeline leak rates, vulnerability of valves, fittings, materials, and welds to hydrogen embrittlement, and effects on natural gas storage facilities [44].

The gas grid is only considered as a mode of transportation in GENeSYS-MOD, but it can also serve as a gas or hydrogen storage [17]. Considering the possibility of hydrogen storage in the gas grid might reduce the overall costs and increase the blending of hydrogen in some parts of the grid. Further adjustments to the model would be needed to account for this and examine the effects of different hydrogen shares in the grid.

To further enrich the discussion on the use of renewable hydrogen in the European energy system of the future, effects of a more detailed representation of the techno-economic aspects of increasing proportions of hydrogen blending in pipelines in GENeSYS-MOD and the implications of global hydrogen trade on Europe are future research aims.

6. Conclusion

As interest in hydrogen as an energy carrier grows, questions arise regarding its effective integration into the European energy system. Despite numerous studies on the techno-economic aspects of hydrogen blending, a notable gap exists in understanding its broader impacts on the European energy system and international trade in the future. This study emloys the open source Global Energy System Model (GENeSYS-MOD) to analyze implications for production, transport options, and regional localization of hydrogen across Europe by 2050 by varying the percentages of hydrogen allowed in existing gas pipelines. The study further includes a trade sensitivity analysis to assess the effects of reducing hydrogen imports from outside of Europe, contributing valuable perspectives to the ongoing discourse on energy security and import dependency.

Results show the inelasticity of hydrogen demand due to its specific use cases and high costs compared to existing competing technologies (e.g. heat pumps and battery electric vehicles). European hydrogen production in 2050 increases by a mere 0.17% for 100%-blending allowed compared to no blending allowed. The production and use of hydrogen entail high costs which often exceed direct electrification. This limits hydrogen to applications where alternatives are currently non-existent (such as aviation) or very costly (e.g., in freight transport or high temperature process heat).

While overall hydrogen production and demand in Europe remain stable with different sensitivities, there are significant differences at national level. Model results show Norway's role as an exporter of hydrogen is increasing significantly with rising blending shares due to the utilization of existing gas pipelines. Turkey and Spain are maintaining their position as important exporters with only slight decreases in exports. France, Germany, and Italy are the largest hydrogen importers in 2050, with Germany increasing its imports most notably due to increased hydrogen exports from Norway. These results illustrate the influence of varying blending shares and geographical proximity on the dynamics of hydrogen trade in Europe.

Regarding energy security, achieving a balance between trade relations and energy independence is key to mitigating risks associated with supply disruptions, price volatility, and geopolitical tensions. Our study emphasizes the need for collaborative efforts to boost renewable energy production, optimize energy efficiency, and purposefully diversify the energy mix to ensure a resilient and self-reliant energy system. Concerns about import dependency on countries from outside the European Union, could be tackled by careful planning in establishing hydrogen "backbones" to avoid potential path dependencies. In this context, our sensitivity analysis underscores the importance of using existing gas infrastructure, especially with higher capital costs for electrolyzers.

To summarize, this article shows that the addition of hydrogen blending on a transmission level does not significantly affect the demand for hydrogen in the European energy system by 2050. However, its immediate impact on the dynamics of production and imports on national levels necessitate careful consideration to ensure a robust and sustainable strategy for Europe's evolving hydrogen landscape. Furthermore, the study highlights the potential risk of reliance on imported hydrogen, as well as the possibility of creating new dependencies that must be carefully evaluated when planning for hydrogen's future in Europe.

CRediT authorship contribution statement

Jonathan Hanto: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Philipp Herpich:** Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Konstantin Löffler:** Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Karlo Hainsch:** Writing – review & editing, Writing – original draft, Validation, Supervision, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Nikita Moskalenko:** Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Sarah Schmidt:** Writing – original draft, Investigation, Formal analysis.

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 model and data used in this research can be found at the public GitLab page of GENeSYS-MOD (https://git.tu-berlin.de/genesysmod/genesys-mod-public) and the open Zenodo repository for GENeSYS-MOD datasets in Hanto et al. [33]. Also, the Open ENTRANCE scenario explorer (https://data.ene.iiasa.ac.at/openentrance/) can be used to visualize and download key results from the Gradual Development scenario that was used in this paper.

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Appendix A. Model description

GENeSYS-MOD is a cost-optimizing linear program, focusing on long-term pathways for the different sectors of the energy system, specifically targeting emission targets, integration of renewables, and sector-coupling. The model minimizes the objective function, which comprises total system costs (encompassing all costs occurring over the modeled time period) [43,35].

The GENeSYS-MOD framework consists of multiple blocks of functionality, that ultimately originate from the OSeMOSYS framework. Fig. A.1 shows the underlying block structure of GENeSYS-MOD v2.9, with the additions made in the current model version (namely the option to compute variable years instead of the fixed 5-year periods, as well as an employment analysis module, in addition to the regional data set and the inclusion of axis-tracking PV).

(Final) Energy demands and weather time series are given exogenously for each modeled time slice, with the model computing the optimal flows of energy, and resulting needs for capacity additions and storages.[4] Additional demands through sector-coupling are derived endogenously. Constraints, such as energy balances (ensuring all demand is met), maximum capacity additions (e.g. to limit the usable potential of renewables), RES feed-in (e.g. to ensure grid stability), emission budgets (given either yearly or as a total budget over the modeled horizon) are given to ensure proper functionality of the model and yield realistic results.

The GENeSYS-MOD v2.9 model version used in this paper uses the time clustering algorithm described in Gerbaulet and Lorenz [27] and Burandt et al. [12], with every 73rd hour chosen, resulting in 120 time steps per year, representing 6 days with full hourly resolution and yearly characteristics. The years 2017-2050 are modeled in the following sequence: 2017, 2022, 2025, 2030, 2035, 2040, 2045, 2050. All input data is consistent with this time resolution, with all demand and feed-in data being given as full hourly time series. Since GENeSYS-MOD does not feature any stochastic features, all modeled time steps are known to the model at all times. There is no uncertainty about e.g. RES feed-in.

The model allows for investment into all technologies and acts purely economical when computing the resulting pathways (while staying true to the given constraints). It usually assumes the role of a social planner with perfect foresight, optimizing the total welfare through cost minimization. In this paper, an add-on allowing for myopic foresight using multiple computational stages, is introduced. All fiscal units are handled in 2015 terms (with amounts in other years being discounted towards the base year).

For more information on the mathematical side of the model, as well as all changes between model versions, please consult [35,43,11,12].

Appendix B. Gradual development scenario

The uniqueness of this storyline is that it describes the challenging energy transition with an equal part of societal, industry/technology, and policy action. Several of these three dimensions take responsibility and deliver tailor-made contributions to reach the least ambitious climate mitigation target (2 °C; remaining storylines envisage 1.5 °C). Carbon pricing in this scenario is more conservative compared to the others. Compared to the other three pathways, instead of focusing on one specific aspect, features and characteristics from Techno-Friendly, Societal-Commitment, and Directed Transition are included in this pathway. Since this pathway culminates in a decarbonization by 2050, the transformation of the energy system is not as drastic as in the other three and measures are more moderate. Costs and efficiencies of all technologies are changed slightly to reflect the pathway characteristics, similar to the Techno-Friendly implementation. Yet, the values are less optimistic and improvements happen at a slower rate. Also, novel and not already proven technologies are not integrated (e.g. Direct Air Capture, overhead trucks, Carbon Capture and Storage) and there is no option foreseen to have net imports of hydrogen from regions outside of Europe. Similar to Societal Commitment, this pathway is also characterized by reductions in energy demand of all different sorts. These reductions, however, are less substantial as in Societal Commitment and, additionally, the potential for demand shifting is far more limited. More information on the different pathways can be found under Auer et al. [5].

Appendix C. Results

While the overall production and demand of hydrogen within the EU barely change over the different sensitivities, significant changes can be found at national level as shown in Fig. C.2. With increasing shares of hydrogen allowed in existing pipelines, Norway's hydrogen exports raise from 44.0 TWh (0%-blending) to 105.6 TWh (100%-blending). As one of the biggest exporters of natural gas, Norway can leverage the existing pipelines to export its hydrogen across Europe.

Spain and Turkey utilizee their renewable potential to produce and export large amounts of hydrogen that only slightly decrease with the

[4] GENeSYS-MOD offers various storage options: Lithium-ion and redox-flow batteries, pumped hydro storages, compressed air electricity storages, gas (hydrogen and methane) storages, and heat storages.

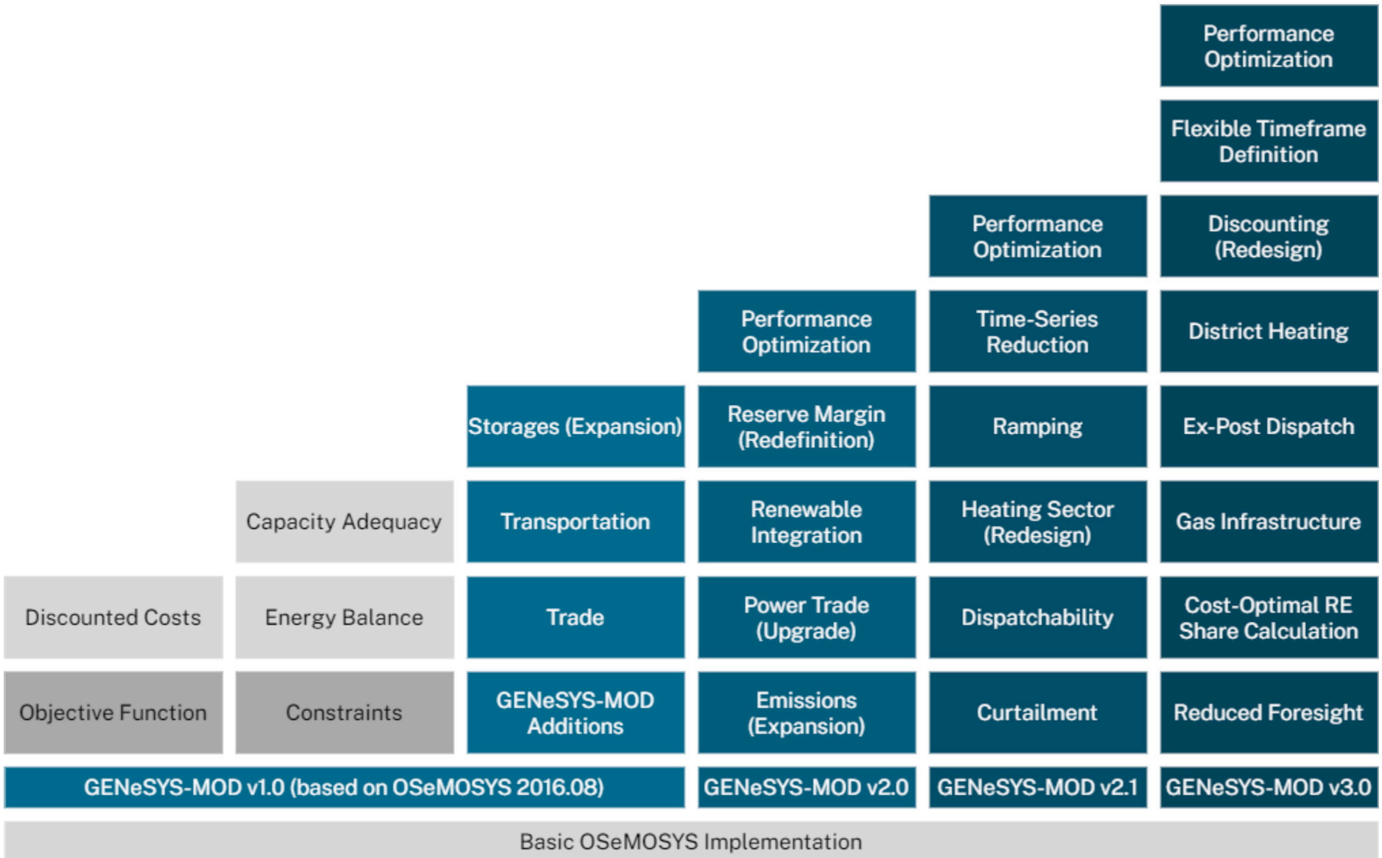

Fig. A.1. Model structure of the GENeSYS-MOD implementation used in this study. Source: Own illustration.

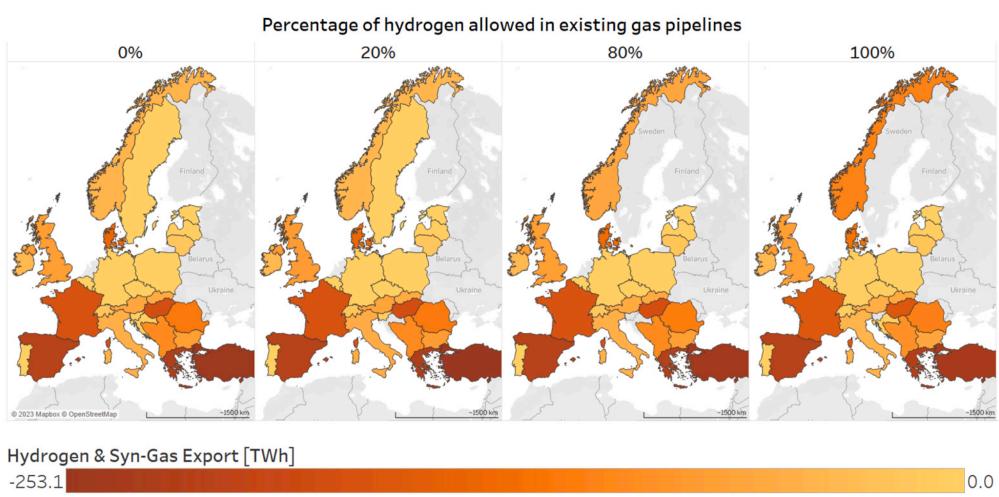

Fig. C.2. Hydrogen and Syn-Gas exports for selected blending shares in 2050. Source: Own illustration.

uptake in exports from Norway. Denmark is also one of the main exporters and decreases its exports the most as Norway is able to provide hydrogen at cheaper costs when using blending. France is actually a net importer of hydrogen, however, due to the substantial volume of Spain's hydrogen exports passing through the country, France still showcases considerable levels of hydrogen export activity.

Fig. C.3 shows the change of hydrogen and syn-gas imports in the European countries in 2050. France, Germany, and Italy are the largest importers. While they consume significant amounts, another reason is that hydrogen and syn-gas from Spain and from Norway, as shares rise, are being transported through them to reach the other countries in Europe.

Appendix D. Results sensitivities

Fig. D.4 shows the hydrogen blend export and import for both hydrogen sensitives in all model regions in the year 2050 according to the methodology introduced in Section 4.2.4. Negative values represent export and positive values represent import of hydrogen blend. In the hydrogen efficiency sensitivity, all blending shares (20%, 40%, and 80%) show an increase in export and import with higher efficiency of electrolyzers (factor 0.5). The main exporters are Norway, Italy, and the UK while Germany and Austria are the largest importers. A decrease in hydrogen blend export and import can be seen when efficiency is reduced (factor 2).

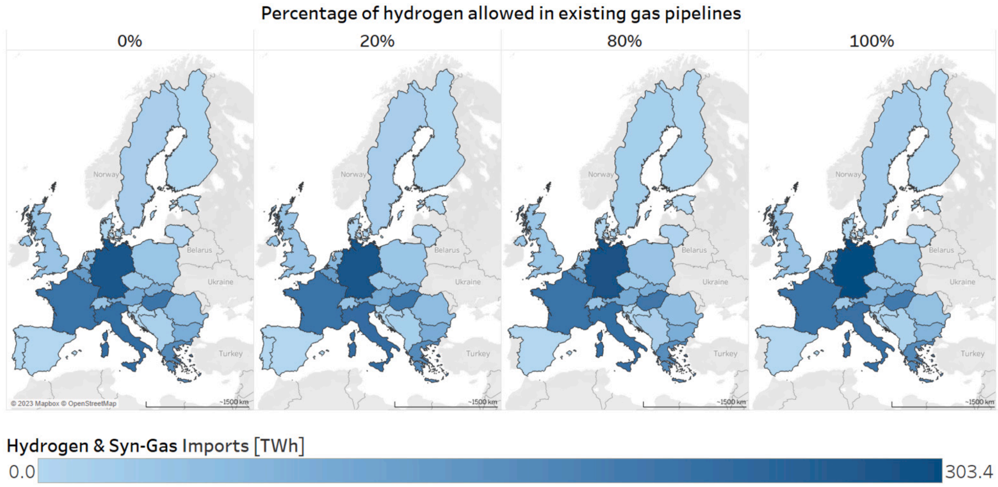

Fig. C.3. Hydrogen and Syn-Gas imports for selected blending shares in 2050. Source: Own illustration.

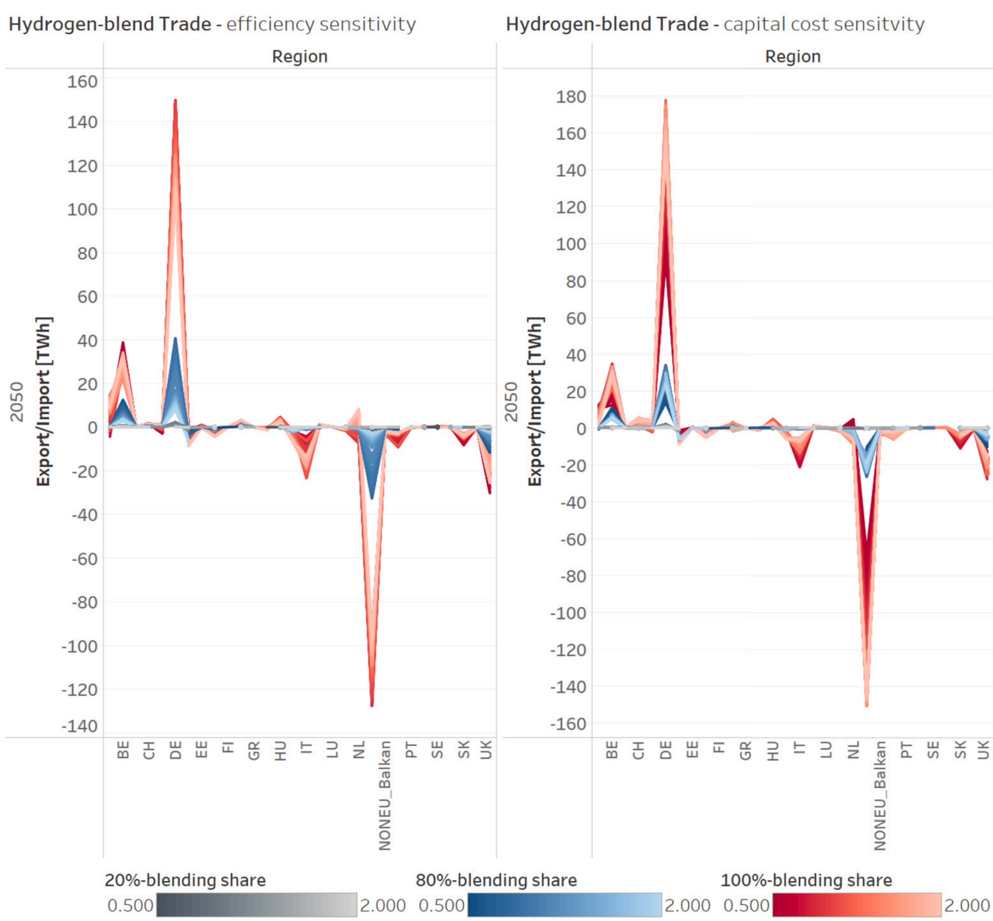

Fig. D.4. Regional Hydrogen blend trade sensitivities for electrolyzer efficiency and capital costs. The color range represents the factor of the respective sensitivity. Source: Own illustration.

For the capital cost sensitivities, results for large importers and exporters are inverted, as lower capital costs (factor 0.5) for hydrogen lead to a reduction in hydrogen blend trade as production of hydrogen is regionalized and the existing gas-infrastructure less utilized. There is, however, an increase in exports for smaller exporters such as Italy, as these routes might be used when readily available for trade to neighbouring countries.

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