Feasibility study Hy3

Hy3 – Large-scale Hydrogen Production from Offshore Wind to Decarbonise the Dutch and German Industry

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1. Executive summary

Green hydrogen is gaining importance as an energy carrier, an enabler of system integration, as well as a feedstock (substitution) for several industrial processes. It will be an important building block for the transition process to a decarbonised energy system. Besides the production of renewable electricity, the production of green hydrogen[1] from offshore wind in the North Sea is promising given its relatively shallow sea depth and favourable wind speeds. This report presents a feasibility study assessing the potential and boundary conditions for green hydrogen production in the Dutch and German offshore and coastal regions of the North Sea from electricity produced from offshore wind and for delivering hydrogen to demand centres in the Netherlands and North Rhine-Westphalia (NRW) from 2025 to 2050. In this context, exploratory scenarios have been developed that explore more than just current energy policy goals[2] and allow us to provide first insights into how a transnational hydrogen economy could look in 2050.

Two key statements were derived from the analysis:

OPPORTUNITY: Cooperation between the Netherlands and Germany in developing a common hydrogen market and infrastructure boosts opportunities for realising a decarbonised regional economy.

CALL FOR ACTION: Trigger joint initiatives to establish a common market, remove regulatory barriers, develop a common vision for hydrogen infrastructure, foster cross border collaboration on industrial transformation, establish joint R&D and innovation initiatives and establish binational projects with net benefits to the Dutch and German energy systems.

The results of the study are summarized below and ultimately provide five key findings and recommendations.

1.1. Results of the feasibility study

How is the existing and future hydrogen demand expected to develop in the Netherlands and North Rheine-Westphalia?

Versatile transportation and industrial applications of hydrogen are to be considered on the demand side. There is a high technology readiness for most hydrogen applications in industry with transportation application close behind. In industry, utilisation of green hydrogen is possible as an alternative to grey hydrogen and in processes that now use fossil fuels. The most promising industry sectors for green hydrogen usage are those that already use hydrogen as a raw material or fuel today, such as basic chemical industries for ammonia and methanol synthesis, naphtha production in refineries, as well as steel, cement and glass production. In the transportation sector, hydrogen can be used in various types of fuel cell electric vehicles (bus, train, heavy-duty vehicles and passenger

[1] Green hydrogen is produced by electrolysis of water, using only electricity from renewable sources. Regardless of the electrolysis technology selected, the production of hydrogen is CO_2-free, as 100 percent of the electricity used comes from renewable sources, which are CO2-free (description from the German National Hydrogen strategy).

[2] Including the German Network Development Plan.

cars). With respect to demand size, the starting point for the assessment of future demand is the current demand for grey hydrogen.

According to analysed scenarios current industrial applications in the petrochemical and chemical industry in North Rhine-Westphalia and the Netherlands have a hydrogen demand of 17 TWh and 41 TWh per year, respectively, which is substantial. The potential future hydrogen market is modelled under the assumption of a cost-optimal energy system for achieving a greenhouse gas reduction target of -95% by 2050. The demand scenario is based on the recent hydrogen roadmap of North Rhine-Westphalia and was adapted to the Dutch industrial areas. Results show that during the initial phase of the scenario, up to 2030, hydrogen demand is primarily governed by commercial transport applications such as trains, buses, light-duty, and heavy-duty vehicles, as well as by substitution of the current hydrogen demand in the chemical and petrochemical industry. Later, between 2030 and 2040, passenger cars and the steel and synthetic fuel sectors become increasingly important. From 2035, the largest long-term impact on demand comes from production of synthetic kerosene, synthetic diesel and synthetic naphtha, under the assumption of decarbonisation of the refinery sector via green hydrogen utilisation. Finally, between 2040 and 2050, a more extensive hydrogen adoption for process heat in high-temperature furnaces and the cement industry is anticipated. By 2050, demand in NRW approaches 162 TWh and in the Netherlands 239 TWh in terms of the above-mentioned sectors. In the considered scenario, a common market involving both NRW and the Netherlands more than doubles the potential hydrogen demand of each region, thus increasing the chances for a large-scale market for green hydrogen.

What are the potentials for green hydrogen production from offshore wind in the Dutch and German North Sea?

For this study, it was assumed that green hydrogen is produced using electrolysis of fresh or desalinated sea water, powered by renewable electricity from offshore wind sources in the North Sea. To assess the potential yield of hydrogen production at the Dutch and German North Sea, onshore and offshore production concepts are investigated in combination with several operational settings of electrolysis facilities. A simplified conceptual configuration of hydrogen delivery to a potential hydrogen backbone pipeline is presumed, with three possible coastal feed-in points, two in the Netherlands (Groningen and Rotterdam) and one in Germany (Emden). Taking into account national offshore wind targets until 2040, the EU Offshore Renewable Energy Strategy and all potentially available areas for the years beyond, a roadmap for the development of offshore wind capacities in the North Sea is developed for the reference years (2025 to 2050). The determined installed capacity of offshore wind parks in the exclusive economic zones in the Dutch and German North Sea by 2050 is ca. 68 GW for the Netherlands and ca. 53 GW for Germany. As far as technically and economically feasible, the available capacities should be used primarily for renewable electricity generation. Based on determined offshore wind capacities, the national offshore wind targets and ambitions for future electrolysis capacity, an electrolysis development roadmap for the North Sea areas is developed. In this respect, a total of five scenarios for the hydrogen production with offshore wind combined with onshore and offshore electrolysis are modelled. The aim is to analyse different conceptual approaches and their implications on scale, costs and timing of hydrogen production from offshore sources. In this respect, the scenarios should be interpreted as exploratory scenarios for hydrogen production from offshore wind and not as optimal energy production scenarios or realistic forecasts. In order to be able to carry out the evaluation of the green hydrogen supply scenarios, some essential simplifications were necessary. When interpreting the results the limits resulting from the assumptions made must be taken into account. First of all, a complete utilisation of the offshore wind potentials for electricity production in each reference year was assumed to be coupled with hydrogen production in the analysed scenarios. Therefore, the derived results on technical and economic data may differ project-specifically (e.g. for certain areas). Only offshore wind was considered as an electricity source. Other sources such as grid electricity, onshore wind or solar energy, could positively influence hydrogen production performance and economics. Furthermore, offshore grid connection points further inland, as described in the German Network Development Plan, were not considered in the analysis. Technological innovations in the early stages of development such as floating wind turbines, hybrid projects, energy islands, etc. could bring additional benefits in the medium to long term, but were not considered in this phase of the analysis. Finally, only the pipeline transport of hydrogen from the offshore plants and no alternatives, such as in-land shipping transport, were considered.

Hydrogen production quantities and scale-up pathways vary substantially between the analysed scenarios due to different operational strategies for the electrolysers. However, in all scenarios, significant production begins from 2035 if 10–50% of electricity from offshore-wind is converted to hydrogen. By 2050, annual hydrogen production from offshore wind could reach 54–139 TWh for the Netherlands and 37–100 TWh for Germany.

The expected production costs of hydrogen including associated costs of transporting electricity or hydrogen to the coastal feed-in points are subject to high uncertainty. This makes it very difficult to provide accurate cost estimates of hydrogen production from offshore wind until 2050. Nevertheless, the cost of green hydrogen production is expected to follow a downward trend. It is probable that it will be competitive with domestic and imported blue hydrogen. These market trends highly depend on prevailing and future commodity prices and diverse regulating mechanisms. Under conservative assumptions we see the costs of green hydrogen supply converge at ca. 4 and 5 EUR/kg by 2040.

How could the demand and supply centres be connected by the repurposed transport network and storages in the Netherlands and Germany and how to match hydrogen supply and demand?

Reliance on the existing natural gas transmission network for future hydrogen transport is anticipated in both the German and Dutch hydrogen strategies. Furthermore, in both countries, gas transmission operators have published their visions for a national hydrogen backbone. The Dutch ministry of Economic Affairs has published the HyWay 27 study for the realisation of a national hydrogen backbone. €750 million has been reserved for this plan. These visions and plans were used as an input for analyses of the transnational hydrogen infrastructure in this study.

The underlying hydrogen backbone consists predominantly of more than 5,000 km repurposed gas pipelines and allows the connection of demand centres with three coastal feed-in supply points. Also, it connects four storage sites with underground salt caverns in both countries – one in the Netherlands and three in Germany, offering flexibility and security of supply. Finally, it connects the hydrogen transport network to two import locations – one in the port of Rotterdam and one import hub in northwest of Germany (Wilhelmshaven, for example). A network model analysis was performed for the demand scenario and for two supply scenarios. Mismatch in hourly demand and supply quantities are covered by storage and import of hydrogen. The results show that green hydrogen produced from offshore wind is not sufficient to meet hydrogen demand in the Netherlands and North Rhine-Westphalia and that additional sources are needed from the start. Bottlenecks in hydrogen pipeline infrastructure may develop near coastal feed-in points and import connections from 2035 onwards, but can be alleviated by diversifying import via other harbours such as Wilhelmshaven in Germany and by additional network reinforcements. Joint grid development between the Netherlands and Germany is required, both for the timely repurposing of the existing gas grid and gas storages for the use with hydrogen as well as for the development of new hydrogen pipelines.

What are the pathways and obstacles towards a potential transnational hydrogen market?

Future business models for the realisation of a green hydrogen market need the right framework conditions. An overview of the respective value chains shows gaps to be bridged with respect to market functions, energy infrastructure, stakeholder roles and market designs. On the other hand, value chains can evolve from the established and functioning offshore wind and gas markets and from existing industry demand.

For the assumptions in this study, the prices for green hydrogen converge at 4–5 EUR/kg by 2040. For blue hydrogen we see costs modelled between 2–3 EUR/kg by 2035 although estimates highly depend on the prevailing and future commodity prices for natural gas and CO_2, being influenced by diverse regulating mechanisms. This suggests the need for support mechanisms for green hydrogen to become and remain competitive and bring down costs further. An enabling market design and regulatory framework is needed to establish certification of green hydrogen, to allow large-scale onshore and offshore integration of power-to-gas technology and to facilitate integrated grid planning for both natural gas and hydrogen. This should also include close cross-border coordination and cooperation.

1.2. Key findings

Large-scale, cross-border hydrogen value chains can contribute to the evolution of renewable electricity and natural gas systems into an integrated and decarbonised energy system. EU, national and regional policies have set ambitious offshore wind and electrolyser capacity targets. The value chains examined in the study fit well within this framework. Cooperation between the Netherlands and Germany in developing a common hydrogen market and infrastructure can foster the opportunities for realising a decarbonised economy. Realizing these opportunities will require coordinated and effective actions that remove remaining barriers and overcome uncertainties. The following key findings can be derived from the results of the study, which call for action by all stakeholders.

1. **Dutch-German cooperation will be beneficial to build up and connect the markets for hydrogen in NRW and the Netherlands.**
   - A common market for both NRW and the Netherlands would more than double the potential demand for hydrogen in this area.
   - Cooperation enables the use of synergies, e.g. higher market volume for services and better utilisation of infrastructure, reduces the risk of stranded assets and increases security of supply in this region.

- Integrated development could achieve better scaling and utilisation of hydrogen infrastructure.

2. **The transformation of the petrochemical and chemical industry structures in the cross border region will drive the demand for hydrogen.**
   - Initial demand for hydrogen in NRW and the Netherlands is expected to be driven primarily by substitution of current hydrogen consumption in the chemical and petrochemical industries, as well as commercial transport applications such as buses, trucks, trains and cars.
   - In the chemical and petrochemical industry, there are a variety of applications for the use of green hydrogen, e.g. for methanol and ammonia production or for decarbonisation of fuel refining.

3. **Coastal and offshore hydrogen production can contribute to the utilisation of the North Sea wind energy potential and to domestic hydrogen supply.**
   - The cost for onshore and offshore green hydrogen production in Germany and Netherlands is not yet competitive, but projections clearly show downward trends. Green hydrogen production from offshore wind is expected to become competitive with domestic and imported blue hydrogen.
   - Hydrogen production onshore and offshore from offshore wind sources is likely to accommodate more wind energy in the system as it helps support decarbonisation strategies for several hard-to-abate sectors at the lowest system cost.
   - Hydrogen production from North Sea offshore wind needs to be assessed in terms of value and cost in relation to other hydrogen sources, sectoral decarbonisation strategies and strategic advantages such as domestic production, security of supply and public acceptance.
   - Both onshore as offshore production concepts need to be further explored regarding the location and optimal operation of the electrolysis and the balance between electricity and hydrogen feed in the energy system.

4. **To meet future hydrogen demand in the Netherlands and NRW, other sources beyond green hydrogen produced from offshore wind in the North Sea are needed in any case.**
   - Green hydrogen produced from offshore wind in the North Sea has vast production potential, but it is still insufficient for meeting the projected hydrogen demand. This deficit in hydrogen production capacity grows exponentially from 2025 to 2050.
   - Other sources of hydrogen in addition to green hydrogen produced from offshore wind will be needed in the future. These other sources can include domestic production of green hydrogen from solar and domestic and imported blue hydrogen.

5. **Repurposing of parts of the existing gas infrastructure in the Netherlands and Germany yields sufficient transport and storage capacity for hydrogen by 2030.**
   - Repurposing of parts of the existing gas infrastructure for hydrogen transport in the Netherlands and Germany yields sufficient transport capacity by 2030. After 2030, bottlenecks could occur in certain regions.

- The development of hydrogen storage in existing and new salt caverns in both the Netherlands and Germany will be a useful and necessary balancing asset for offering flexibility to the energy system. One to five caverns will be needed in 2030, with this number increasing to 49 to 57 caverns by 2050. These estimates only consider storage capacity needed to balance supply and demand fluctuations for a year with normal weather. Factoring in strategic reserves and yearly variations in supply and demand would likely increase the storage need.
- Gas storage sites currently using caverns for gas storage offer a large technical potential for hydrogen storage. However, in order to support new hydrogen infrastructure, new caverns will likely be needed during transition phase where both natural gas and hydrogen storage capacity will be necessary.
- A coupled binational approach brings synergies and efficiency in terms of capacity and utilisation of storage and pipelines, for example. To leverage synergies a joint vision for a hydrogen infrastructure between the Netherlands and Germany is required. Grid repurposing and renewing takes multiple years from planning to executing, highlighting the need for urgent coordinated NL-DE action to meet 2025 and 2030 goals.

1.3. Recommendations

This feasibility study was prepared in the context of the Dutch-German Green Hydrogen Cooperation with the aim to put Germany and the Netherlands on the forefront of global green hydrogen deployment in an energy system relevant scale. It makes an important contribution to current discussions and issues in the context of decarbonising industry with hydrogen and the potential use of offshore wind for hydrogen production. The large number of projects currently announced shows that the topic is important to stakeholders and politicians alike. It is important to use the current momentum and strengthen the cooperation between the two countries in order to clarify open issues and enable the development and implementation of successful projects. The following recommendations are intended to facilitate this process.

1. Dutch-German Green Hydrogen Cooperation

First of all, the Netherlands and Germany should further investigate potentials and instruments for cooperation with the aim of developing the hydrogen economy in the cross-border region in a coordinated manner and developing it with the close involvement of North Rhine Westphalia and Lower Saxony and relevant stakeholders (e.g. authorities, energy agencies, project coordinators). It is reasonable to establish a continuous exchange of experience on open questions in the context of hydrogen production, transport and use, such as power supply, grid connection or quality standards, and on framework conditions at national and European level. Furthermore, the cooperation between the Netherlands and Germany should be used and communicated as a lighthouse project to make the development of transnational hydrogen value chains visible in Europe.

2. Grid, network and storage infrastructure

To support the development of grids, networks and storage facilities, the Dutch and German grid operators for electricity and gas should be invited to identify potentials and projects for cooperation for the region on grid infrastructure and hydrogen storage that complements and deepens the national and European planning and derives a joint step-by-step approach.

3. Hydrogen market and trade

The transnational market and hydrogen trading should be supported by exchanging market information (e.g. expected demand over time) and developing strategic measures regarding the import and integration of hydrogen from international markets. In the long run, the development of a Dutch-German hydrogen market hub matching system should be developed and supported, connecting players from demand and supply side.

4. Industrial transformation

The exchange with industry partners should be continued, and the governments should establish and support transnational networks and working groups of industrial enterprises with high transformation pressure to accompany change in the industrial value chain. The petrochemical and chemical industry in the considered region is already strongly linked. Close cooperation already exists through the "Trilateral strategy for the chemical industry" and other cross-border collaborations [124]. Thus, a joint strategy for the transformation of industrial regions is recommended.

5. R&D and innovation

The existing binational innovation and university networks should be used and expanded in order to develop and promote research & development cooperation opportunities in the field of hydrogen and to support research activities. Important research questions concerning electrolysis, hydrogen transport and storage as well as industrial applications could be jointly worked on. This should be supported by creating a regulatory framework that promotes cooperation of stakeholders from both countries. One focus should be on further studies regarding cost aspects, realisation and operating options for hydrogen production from offshore wind and subsequently the role of hydrogen in transforming the existing industrial value chain towards climate neutrality. Another focus should be on basic research in electrochemistry, such as electrolysis processes and the use of raw materials. In this context, also the transfer of information and the dissemination of new technologies, concepts and services between the two countries should be further supported by establishing a regular binational "Hydrogen innovation days" event, for example.

6. Perspective from the energy system level

Finally, the results of this feasibility study must be considered from a system level. It is recommended to examine more deeply what role offshore hydrogen production could play in a balanced mix of offshore renewable energy supply options in relation to national and European (offshore) renewable targets. The development of demonstration projects in binational and European context addressing the system level value, such as within in the IPCEI program, should be supported by the Dutch, the German and the North Rhine-Westphalia governments.

2. Introduction

2.1. Background

The European Union (EU) aims for a climate-neutral energy system by 2050 and is in the midst of the energy transition. International cooperation is essential if this is to succeed. This is especially true for the Netherlands and Germany – countries that share both a land and a sea border. Furthermore, both countries have ambitious goals concerning the further expansion of offshore wind energy production and are front-runners in investigating and promoting hydrogen utilisation.

With the Joint Declaration of Intent on the Energy Transition, the Ministry of Economic Affairs and Climate Policy of the Kingdom of the Netherlands and the Federal Ministry for Economic Affairs and Energy of the Federal Republic of Germany declared their ambitions for energy policy cooperation. The declaration envisages the joint cross-border development of offshore wind projects and infrastructure development in the North Sea region. Hydrogen with its potential to serve as an energy carrier, enabler of sector coupling and system integration, as well as a feedstock for several industrial processes was identified as a key topic. The development of European, Dutch, and German hydrogen strategies and the North Rhine-Westphalian hydrogen road map further establishes a political framework for hydrogen market development.

The trilateral project “Hy3 – Large-scale Hydrogen Production from Offshore Wind to Decarbonise the Dutch and German Industry” was initiated by the Netherlands, the Federal Republic of Germany, and the German Federal State of North Rhine-Westphalia (NRW). Its realisation is assigned to TNO as assigned party for the Netherlands, the research centre Forschungszentrum Jülich (IEK-3) as the assigned party for the German Federal State of North Rhine-Westphalia, and the Deutsche Energie-Agentur (dena) – the German Energy Agency – as the assigned party for the Federal Republic of Germany.

2.2. Goals

The resulting study, which is the first of its kind, aims to assess the feasibility of a transnational green hydrogen supply chain in the Netherlands and Germany. The analysis time frame spans from 2025 to 2050.

Decarbonisation of a strong industry base in the Netherlands and North Rhine-Westphalia could be partly realised by green and low-carbon hydrogen deployment. Therefore, an examination of existing and potential field of hydrogen applications in the industry and transportation sectors is one of the main goals of this research. The overarching question is, how is the existing and future hydrogen demand in the Netherlands and North Rhine-Westphalia expected to develop?

Furthermore, the research aims to investigate the potential for green hydrogen production in the offshore and coastal regions of the Dutch and German North Sea. Today, a large-scale hydrogen production from offshore wind is still a visionary concept, but in the context of highly ambitious plans for offshore wind utilisation scale-up and electrolysis development targets in both countries, it could play a major role in the future. Therefore, the second major goal is to answer the question: what are the potentials for hydrogen production from offshore wind in the Dutch and German North Sea?

In both the Netherlands and Germany, natural gas markets play a significant role in the current energy system. Moreover, transport and storage gas infrastructure of both countries is interconnected and serves a transnational gas trade. In the future, repurposed and upgraded gas pipelines and storages could provide a backbone for the potential transnational hydrogen market. In this respect, the third central question to answer is, how could the demand and supply centres be connected by the repurposed transport grid and storage systems in the Netherlands and Germany and how can hydrogen supply and demand be matched?

Prospects for a future green hydrogen market are still hampered by various challenges. Although recent Dutch, German and European policy goals see an important role for hydrogen in the energy transition, sustainable business models for a large-scale hydrogen projects are yet to emerge. In the course of the research, a framework for a transnational Dutch and German hydrogen market is analysed, including value chains, green hydrogen competitiveness, and development of hydrogen backbone and regulatory issues. Thus, the final goal of the report is to examine the pathways and obstacles towards a potential transnational hydrogen market.

2.3. Structure of the report

The initial step in the analysis is to determine technological aspects, market sectors, spatial distribution and the size of hydrogen demand. Hydrogen demand for industry and transportation is then modelled for the identified demand clusters in the Netherlands and North Rhine-Westphalia. These aspects are covered in Section 3, which was prepared by the Forschungszentrum Jülich (IEK-3).

Section 4, which was prepared by dena, offers an analysis of green hydrogen production from offshore wind. Analysis was performed in cooperation with the Fraunhofer Institute for Energy Economics and Energy System Technology (FIEE), which carried out the required modelling. It includes a roadmap for reaching full potential of offshore wind in the Dutch and German North Sea and for the scale up of coastal and offshore electrolysis for hydrogen. Hydrogen production yield and costs are modelled for several scenarios. Additionally, an assessment of CO_2 emission savings from utilising green hydrogen is performed.

In Section 5, which was prepared by the TNO, hydrogen transport and storage infrastructure is examined, under the assumption of using mainly repurposed natural gas infrastructure in the Netherlands and Germany. To meet expected hydrogen demand, additional import routes are considered apart from hydrogen production from offshore wind. Scenarios are modelled for the assessment of pipeline and storage capacities and potential bottlenecks.

Market potentials and barriers for the realisation of the envisaged transnational hydrogen market between the Netherlands and Germany are considered in Section 6, which was jointly prepared by all three institutions. Here, several aspects for market development are examined: value chains, cost of hydrogen supply, pathways for development of an international hydrogen backbone, and regulatory frameworks.

3. Hydrogen demand

The benefits of a transnational green hydrogen economy are firmly based on the expected future hydrogen demand scenario. The main drivers for hydrogen demand are market diffusion/adoption based on technology readiness and underlying business cases. For this reason, Section 3.1 shows an assessment of relevant transportation and industrial hydrogen technologies, and Section 3.2 offers an assessment of the future hydrogen market. Based on today's demand, the possible future market diffusion of hydrogen technologies, together with the quality requirements for the hydrogen needed, are described. Finally, Section 3.3 quantifies the resulting hydrogen demand for NRW and the Netherlands in 2030 and 2050. A particular focus is on the sectoral structure and spatial distribution of thy hydrogen demand.

3.1. Technology assessment

Green hydrogen can be used in a comprehensive range of applications. In this study, transportation and industry are in focus. The advantage of using hydrogen as fuel or feedstock is that it does not lead to carbon dioxide emissions. In addition, combustion-based nitrogen oxide and particulate matter emissions can be avoided when using fuel cells for energy conversion. The following section assesses the available hydrogen-based technologies for transportation and industry together with its required hydrogen quality. Other applications and sectors, such as the electricity sector, are not being analysed but could play an important role in future demand and greenhouse gas reduction.

3.1.1. Transportation

A wide range of hydrogen vehicles by various manufacturers is under development, with the first vehicles already available on the market. Available – or soon to be available – vehicles are buses, trains, heavy-duty vehicles (HDVs) with a gross load above 3.5 metric tons, light-duty vehicles (LDVs) with a gross load under 3.5 metric tons, and passenger cars.
These vehicles use an electrified drive train where very pure hydrogen (> 99.999%) is converted to electricity in a fuel cell equipped with a system of more than 60% efficiency due to advantages in efficiency. The resulting electricity then powers an electric engine. The use of an internal combustion engine would result in a significantly lower efficiency [1].

A fuel cell converts chemical energy into electrical energy under a continuous supply of hydrogen and air. Several fuel cell technologies such as alkaline or polymer electrolyte membrane (PEM), with different characteristics, are currently available on the market. For the requirements of vehicles, the PEM fuel cell has decisive advantages due to its high power density, compact design, easily controllable operating temperatures (approx. 80°C) and dynamic load behaviour [2]. The hydrogen is stored in gaseous form in tanks with high pressure of 350 or 700 bar, depending on the vehicle class. The ongoing discussion on technical standards for long-distance HDVs also includes on-board liquefied hydrogen storage.

The European Commission's revised Renewable Energy Directive (RED II) has set a target for the transportation sector of at least 14% renewable energy in 2030 [3]. Additionally, the Clean Vehicle Directive of the European Union gives quotas for alternative drive trains in new procurements of buses and heavy-duty vehicles [4]. The main alternative to motorised private transportation by fuel cell electric vehicles (FCEV) is battery electric vehicles (BEV). With their respective strengths, they complement existing FCEV technology. The market for FCEV is expected to grow rapidly in the next few years.

In comparison to BEVs, FCEVs enable high ranges and high payloads due to its low system weight and the high energy density of hydrogen. Refuelling an FCEV is similar to refuelling conventional passenger cars and is normally completed within three minutes [5]. Consequently, a high level of flexibility is ensured when using FCEVs. Nevertheless, the efficiency of FCEVs is lower than the efficiency of BEV and the availability as well as the production volume of vehicles is limited, which leads to high vehicle costs. Both FCEV and BEV require a new refuelling infrastructure, including hydrogen refuelling stations or charging points, respectively.

Fuel cell bus

Fuel cell buses (FCBs) for public transportation are already developed, resulting in a technology readiness level (TRL) of 9, which means it offers a qualified system with proof of successful use [6] [7]. Currently, several manufactures offer fuel cell buses. Nevertheless, production quantities are still limited, and there can be longer delivery times. The operation of FCBs ensures usual procedures in a cross-line use for the bus operator, resulting in no bigger vehicle numbers for a FCB fleet than a usual conventional fleet [8]. A typical FCB comes with a tank size of approx. 40 kg at 350 bar pressure and consumes approx. 9.6 kg of hydrogen per 100 km [2] [9]. Consequently, the operating range is around 400 km, enough for service rural areas. Compared to a conventional bus that consumes 41.8 l crude-oil based diesel per 100 km, the fuel cell bus saves up to 1,053 g of CO_2 per km if the hydrogen used is produced with zero GHG emissions [2].

Fuel cell train

Manufacturers deliver fuel cell trains for public transportation for use on non-electrified routes as an alternative to diesel trains. The TRL is 8, meaning a qualified system with proof of functionality in the field of application is present [6] [7]. As with buses, production quantities are still limited, and there can be longer delivery times. Fuel cell trains store around 180 kg of hydrogen in 350 bar tanks and consume around 28.5 kg of hydrogen per 100 km [9]. Thus, the operating range can reach up to 600 km depending on the track profile. In comparison to a conventional train with approx. 129 l diesel consumption per 100 km, a fuel cell train saves up to 3,300 g of CO_2 emissions per km [10].

Fuel cell heavy-duty vehicle

Like fuel cell trains, fuel cell heavy-duty vehicles with a gross load of more than 3.5 metric tons have a TRL of 8, with proof of functionality in the field of application [6]. Vehicles in the 26 t class for distribution services are a particular focus of development. But the development of vehicles for long distances is also gaining traction. Again, production quantities are limited, and there are longer delivery times. For the exemplary case of distribution services, fuel cell trucks with a 350 bar storage capacity of 32 kg and consumption of 8 kg of hydrogen per 100 km, the operating range would be up to 400 km [11]. The fuel cell vehicle saves up to 670 g of CO_2 per km in comparison to a comparable conventional vehicle with 26.7 l diesel consumption per 100 km [12].

Fuel cell passenger car

Fuel cell passenger cars represent a mature technology with a TRL of 9, i.e. a qualified system with proof of successful use [6][7]. Pioneering manufacturers are typically based in Asia. Even though the technology is mature in general, the availability on the market is still limited, as production quantities are limited. Hence, longer waiting times for delivery should be taken into account. Hydrogen tanks for fuel cell passenger cars store more than 5 kg of hydrogen at 700 bar pressure and consume less than 0.9 kg of hydrogen per 100 km [9] [13]. Therefore, the operating range is above 560 km per filling. The fuel cell vehicle saves up to 162 g of CO_2 per km in comparison to a comparable petrol vehicle with 7.9 l/100 km petrol consumption [12].

Infrastructure needs

Fuel cell vehicles are refuelled at hydrogen refuelling stations (HRS), similar to conventional refuelling stations. Therefore, a widely distributed infrastructure is necessary. HRS are available in several sizes, which differ in dispense pressure, daily dispense capacity and dispenser number. The TRL is 8 [6]. Public small hydrogen refuelling stations with one dispenser and a daily dispense capacity of 200 kg at 700 bar can refuel more than 40 fuel cell passenger cars per day. In contrast, medium-sized HRS are typically used in non-public depots for buses or heavy-duty vehicles with two dispensers and a daily dispense capacity of 500 kg at 350 bar, which can refuel more than 20 fuel cell buses per day with a daily range of 250 km. Large HRS with four dispensers and a daily dispense capacity of more than 1,000 kg are still rare but could refuel up to 200 passenger cars or 40 buses per day. Recently, new HRS projects show development towards HRS for parallel distribution of hydrogen with a pressure of both 700 and 350 bar. With such HRS, all road vehicles could be refuelled, ensuring improved utilisation rates of the HRS and in turn, better economic efficiency. This can be further improved by establishing modular HRS concepts that can flexibly respond to demand development [8]. The hydrogen can delivered by trailer with a capacity of up to 1,100 kg of H_2 [2].

3.1.2. Industry

Hydrogen has the potential for significantly reducing the industry's greenhouse gas emissions by using green hydrogen from renewable energy sources. Today, natural gas, coal, diesel and liquefied petroleum gas are common energy sources for low and high-temperature heat, as their market prices are relatively low. Some industrial processes in the chemical industry and refineries use hydrogen as feedstock. Hydrogen used in these processes is typically produced by steam methane reforming of natural gas and carbon-containing residual gases, which means they are not climate-friendly.

Starting points for decarbonising the industry are the utilisation of green hydrogen, where CO_2-emitting grey hydrogen is used today, as well as a technology switch from processes that use fossil fuels to green hydrogen. Due to their high primary energy demand, the energy-intensive basic chemical industries' ammonia and methanol synthesis, naphtha production in refineries, as well as steel, cement and glass production move into focus of the NRW

Hydrogen Roadmap and this study [14]. These industries have a significant demand for high-temperature process heat.

Basic chemicals

The main processes of the industry for basic chemicals considered here are ammonia and methanol synthesis. As described in an analysis accompanying the hydrogen roadmap of North Rhine-Westphalia, ammonia is typically produced via the Haber process with hydrogen produced from steam methane reforming of natural gas [15]. The technological adaption is restricted to a substitution of grey hydrogen from steam methane reforming by green hydrogen from renewable energy sources. The existing technology is mature and consequently the TRL is 9. The total hydrogen demand of the process does not change by switching to green hydrogen. The required nitrogen must be provided by an air separation plant in the new configuration. An adaption of process components is required. The TRL is therefore 8–9.

The situation is different for methanol synthesis. The hydrogen required for methanol synthesis is supplied by partial oxidation of heavy oil or steam methane reforming of natural gas. The additionally required process heat is supplied by burning heating oil, in addition to heavy oil and natural gas. Green hydrogen can be used for methanol synthesis, instead of grey hydrogen (if a carbon source is available) and heat production in the future. If the process heat is supplied by green hydrogen, hydrogen demand for methanol synthesis increases in comparison to the current process based on fossil fuels.

Naphtha, as one of the most important basic petrochemical materials, is generated from crude oil that is split in steam crackers to olefins and aromatics. The by-products hydrogen, heavy oil, refinery fuel gas and naphtha cracker-off gas are used for process heat. The power-to-liquid route using Fischer-Tropsch synthesis is an alternative option for producing naphtha in the future. Dechema specifies a TRL of 9 as of 2030 [16]. An alternative for providing process heat could be green hydrogen or electricity. A TRL of 9 is expected around 2035.

Steel production

Coal and coke are used today to reduce iron ore in a blast furnace to produce steel. This primary steel is complemented by secondary steel from steel scrap. As no iron ore has to be reduced in the secondary steel route, the energy demand is significantly lower. Nevertheless, this route is limited due to the availability of steel scrap. In the future, the use of hydrogen is a promising option for reducing iron ore as an alternative to coal and coke. The resulting sponge iron can be melted into steel in electric arc furnaces. A TRL of 9 is expected at around 2035 based on relevant projects [15] [17].

Process heat

Process heat generation in the industry is currently mainly based on the combustion of natural gas, coal or residual gases coming from industrial processes. More climate-friendly options are sustainable bio-energy and green hydrogen. The production of high-temperature heat – above 400°C – is particularly hard to decarbonise as current heat pumps cannot be used in that temperature range. Green hydrogen can complement electrical process heat generation, depending on electricity and green hydrogen supply conditions [18]. The TRL is 9 [16].

3.1.3. Hydrogen quality

The different requirements of the individual components along the supply chain regarding the state and purity of hydrogen require purification, compression, and liquefaction. The selected way of hydrogen storage is amongst the most important variables defining the required processing steps. Electrolytic production of hydrogen is generally facilitated between 1 and 20 bar, while hydrogen fuel cell applications for transportation operate at 350–700 bar. This pressure difference creates a significant pressure differential that must be bridged. Moreover, the high-pressure components of the hydrogen supply chain, such as high-pressure pipelines and 500 bar trailers, add even further constraints to the design of the supply chain.

Hydrogen purity requirements are primarily defined by the hydrogen quality constraints of the final hydrogen consumer. The polymer electrolyte fuel cells (PEMFCs), which are the most common type of fuel cells among the transportation applications, have a 99.97% purity requirement for hydrogen, with orders of magnitude higher limits for individual contaminants such as O_2, CO_2, and H_2O [17][1].

The levels of the required hydrogen purity vary among the different industry segments. Hence, varying purification needs for the demand applications in the specific industry have an impact on the final hydrogen delivery cost. The purity requirements range from 99.95% to 99.995% for general industrial applications providing, amongst others, high temperature process heat to 99.999% and 99.9997% for semiconductors and special applications of gaseous and liquid hydrogen, respectively [18]. Furthermore, verification of hydrogen quality varies between the physical state of hydrogen (gaseous or liquid). Accordingly, industrial applications have requirements for hydrogen purity comparable to PEMFCs used in the transportation sector, leading to high purity requirements for the hydrogen supply chain. Requirements for high temperature heat applications can be lower; however, in order to utilize the network effects the infrastructure would need to be designed to meet the requirements of all consumer segments.

Table 1: Classification of gaseous hydrogen purity levels [20]

Quality verification level	Typical uses	Hydrogen purity
B	General industrial applications (mainly high temperature process heat)	99.95%
D	Hydrogenation and water chemistry	99.99%
F	Instrumentation and propellant	99.995%
L	Semiconductor and special applications	99.999%

Table 2: Classification of liquid hydrogen purity levels [20]

Quality verification level	Typical uses	Hydrogen purity
A	Standard industrial applications, fuel and standard propellant	99.995%
B	High purity: industrial, fuel and propellant	99.999%
C	Semiconductor	99.9997%

3.2. Market assessment

Section 3.1 discussed the high technology readiness for most hydrogen applications in the industry, with transportation close behind. Section 3.2 shifts the focus from a technical to a market perspective. It starts by presenting the current hydrogen demand for industrial applications in the steel and petro chemical and chemical industries, before discussing the total market potential for North-Rhine Westphalia and the Netherlands. Finally, a base market diffusion scenario based on a literature study is presented.

Ammonia, methanol, and steel plants and refineries will be assessed in order to estimate the market potential of hydrogen in the industry. Ammonia, methanol and steel plants are assumed to work with 0.18 $kg_{H_2}/kg_{ammonia}$, 0.19 $kg_{H_2}/kg_{methanol}$ and 0.06 kg_{H_2}/kg_{steel}, respectively [19]. All non-recycled steel output is assumed to switch to DRI by 2050. In addition, synthetic naphtha to be used in the chemical industry is necessary to compensate the decreasing production of crude-oil based naphtha as a consequence of emission reduction targets. Therefore, hydrogen demand required for synthetic naphtha production is also included in the PtL group. Hydrogen demand for PtL applications is estimated by scaling German demand for fuels by the capacities of refineries both in North-Rhine Westphalia, and in the Netherlands [3-6]. Due to the electrification of the transport sector, declining crude-oil based fuel production is assumed to be replaced by PtL pathways, while maintaining the necessary industrial capacities in the region and the role of refineries as naphtha and synthetic fuel providers.

The future development of passenger and freight transport demand is taken from the climate pathways for the Germany study [2]. For the regional allocation the annual driving distances for vehicles within the Netherlands (except trains) are obtained from publicly available data, which is provided by the Dutch Central Agency for Statistics [20]. The figures for the average annual distance of Dutch trains (passenger and goods) are obtained from Eurostat [21]. The relevant data for transport demand in NRW is obtained from the NRW H_2 Roadmap [15]. Due to the fact that the aggregation of NUTS2 regions is used, it can be seen as good approximation of the future allocation of transport demand. As reported by Cerniauskas et al., the weighted average efficiencies are calculated for the different transport segments by using the efficiencies of today's and efficiency projections [22]. Based on this, the average annual distance and corresponding efficiencies are multiplied to project the respective hydrogen demand. Fuel consumption of cars, buses and trains for today is assumed to be 0.9, 9.7 and 28.5$kg_{H_2}/100\ km$, respectively. Technical progress is expected to result in decreased fuel consumption of 0.63, 8.0 and 25.5$kg_{H_2}/100\ km$, respectively. The efficiencies for LDVs and HDVs on the other hand depend on vehicle weight class. Conservatively, the maximum weights of individual categories are used in the efficiency calculation of these two vehicle classes.

As previously discussed, hydrogen as a commodity already has a wide range of applications in the petrochemical and ammonia industry. Given the high concentration of the chemical industry in NRW and the Netherlands, both regions have a substantial hydrogen demand (refineries, methanol, ammonia) of 17 and 41 TWh/a, respectively. As shown in Figure 1, the structure of current hydrogen demand in NRW and the Netherlands is similar, with exceptionally high demand for ammonia in the Netherlands. Given the similarities of the current hydrogen market in these regions, the development of hydrogen demand in both regions can be analysed together meaningfully. This is because every similar policy measures can be easily applied to both regions, such as by creating hydrogen valleys that focus on local hydrogen clusters of industrial and transportation demand, which can support hydrogen market adoption.

The allocation of the current hydrogen demand indicates two broader transnational demand clusters: the demand cluster along the North Sea coast, stretching from West to North, and the regions around the Rhine-Ruhr area, including the Limburg region in the southeast of the Netherlands. Hence, while large parts of hydrogen demand in NRW are concentrated in one area, which is supplied via a hydrogen pipeline, the demand in the Netherlands is substantially more distributed. While demand in the northern Netherlands can be supplied directly from offshore wind, green hydrogen supply for ammonia production in the Limburg area requires a more complex hydrogen infrastructure development. However, given the relative proximity of Limburg to the demand clusters in North-Rhine Westphalia and the numerous existing natural gas pipelines between the regions, an integrated assessment will provide a more cost-efficient result. At the same time, hydrogen pipelines are envisaged in northwest Germany in order to connect the hydrogen production at the North Sea coast with NRW, neglecting potential synergy effects with the pipeline grid in the Netherlands [23].

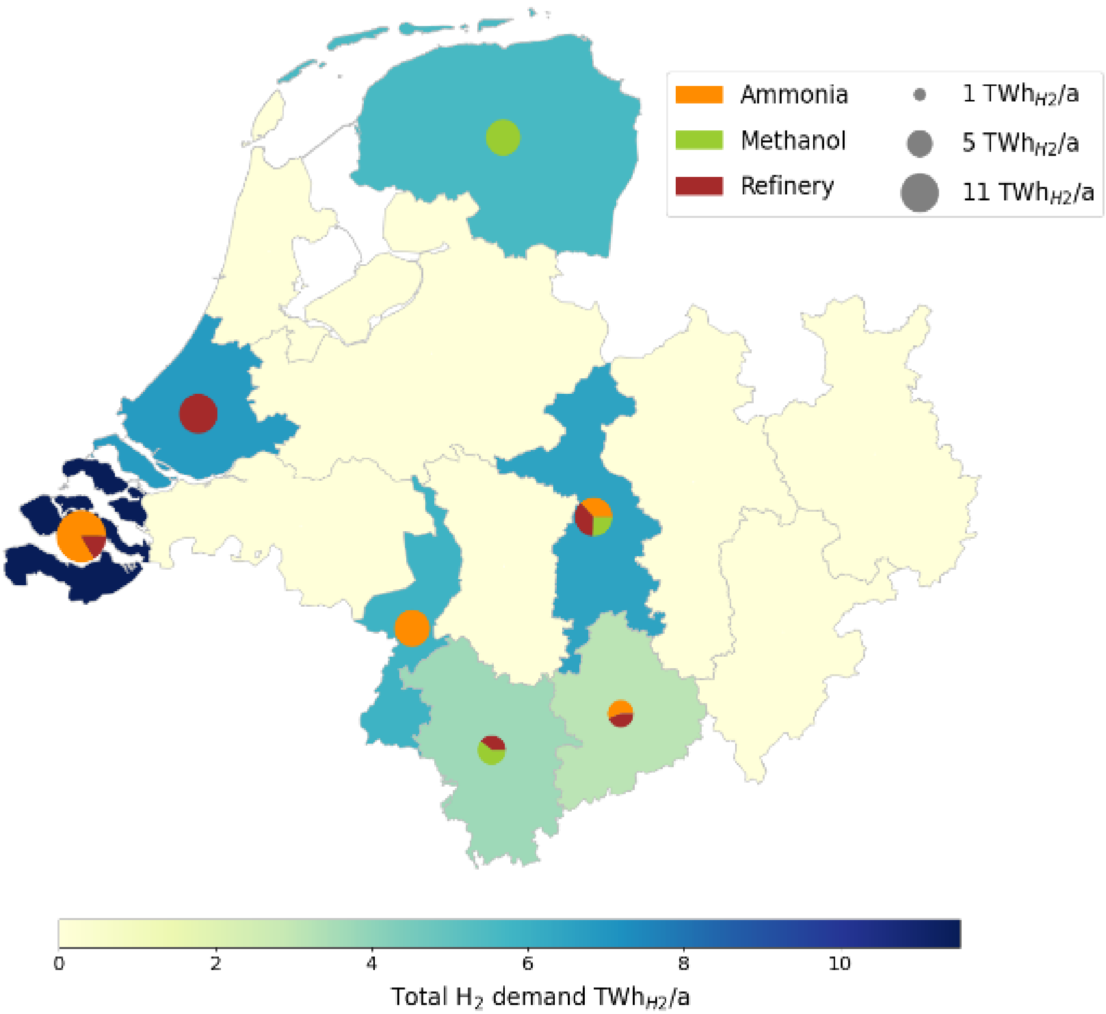

Figure 1: Current hydrogen demand for ammonia, methanol and refinery in NRW and Netherlands

Figure 2 depicts the overall structure for the potential hydrogen demand in both NRW (214 TWh) and the Netherlands (292 TWh), making a total of over 500 TWh used in the further analysis. Not all potentials are additive; however, as the demand for refineries is later substituted by the demand for PtL production as an example. In case of refinery, ammonia and methanol, current demand for hydrogen in both regions is used to determine the potential. The potential demand in NRW stands out due to the importance of the PtL and steel, as these two markets make up two-thirds of the overall demand potential. In the Netherlands, steel production plays a significantly smaller role. This is compensated, however, by an even larger refining capacity, resulting in more than 55% of the demand potential in the Netherlands from PtL.

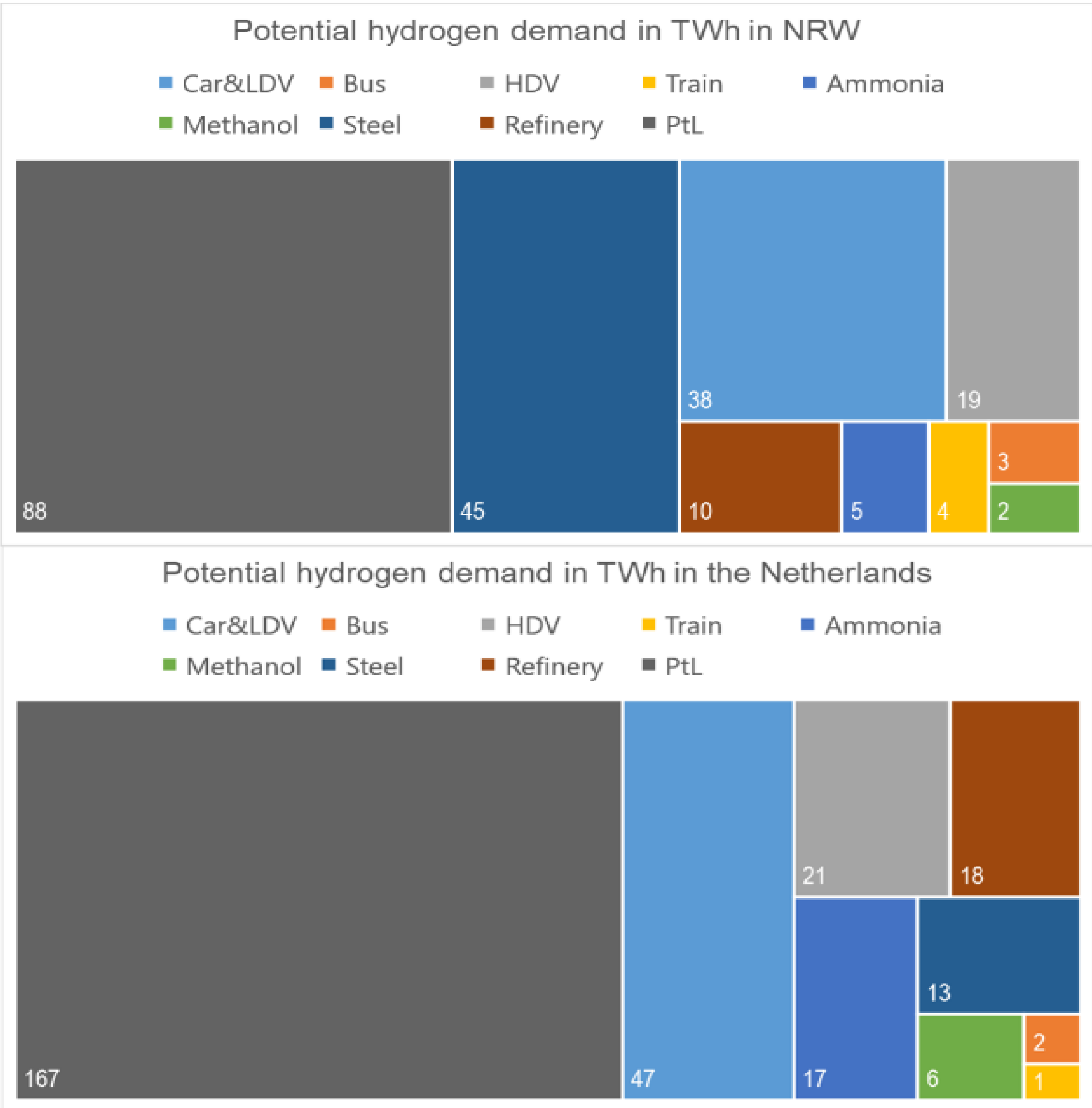

Figure 2: Potential hydrogen demand in NRW (214 TWh) and the Netherlands (292 TWh)

Methodology

The underlying demand scenario for the NRW H_2 Roadmap is derived using a model family largely based on FINE, the freely available model generator [12] [15]. With it, different energy flows of energy systems can be modelled in high temporal and spatial resolution and calculated in a cost-optimal way under the condition of GHG reduction targets. The individual model components are coupled with each other and applied iteratively so that the respective strengths of the individual tools come to bear. This approach has several distinct features, which are:

- Detailed mapping of PtX pathways from primary energy to energy use
- Consistent consideration of sectoral interactions
- High temporal and spatial resolution of infrastructures and renewable power generation
- Mapping of future energy infrastructures (electricity, gas, H2) and storage with high spatial resolution
- Detailed representation of renewable potentials especially wind and PV as well as electrolysis sites
- Mapping of future global energy markets (e.g. hydrogen, synthetic fuels)
- Determination of robust and macroeconomically optimised GHG reduction strategies taking into account data uncertainties by applying new methods

The energy system model FINE-NESTOR (National Energy System Model with Sector Coupling) is the model applied to derive the scenario for hydrogen demand. It maps the national energy supply from primary energy supply to the conversion sector, right through to the end-use sectors. The sectors are represented in the form of technologies or process chains and linked via energy flows. The technologies are characterised in terms of energy, emissions and costs. The model is designed as a closed optimisation model with the objective function of the minimisation of total system costs. Investment decisions to reach a cost-efficient transition are modelled from the macroeconomic, and not from the microeconomic perspective. Therefore, the results do not reflect the decisions of individual market participants, but rather show an idealised picture where all costs in the system are internalised during the decision-making process. Furthermore, the results are subject to uncertainties related to technology development in the future, as projections for technical and economic parameters, such as investment costs and efficiencies, were applied in the assessment. The model represents only part of the national economy, meaning it is a partial equilibrium model. Given a CO_2 mitigation path, the FINE-NESTOR model can be used to calculate the cost-optimal transformation strategy for the entire energy system required to reach the reduction targets for CO_2 emissions.

The model has a temporal resolution in the hourly range in order to be able to represent the fluctuating feed-in of renewable energy and its effects in a problem-oriented manner. Particularly against the background of the increasing importance of sector coupling, a special advantage of the model approach is that all interactions of the energy system can be consistently taken into account. The model also uses a methodological approach that allows for cost uncertainties to be adequately addressed (see Lopion et al. [21]). Drivers of the model are energy consumption-determining demands (such as population development, gross value added, goods demands, transport demands, etc.), which are exogenously specified and are not part of the optimisation. The model is based on a myopic approach, i.e. on an approach that successively minimises the respective costs for the respective time intervals. To determine the transformation strategy, a back-casting method is used in a first step. It is based on the concept of first optimising the energy system of the target year as freely as possible and, based on the result, defining upper and lower limits for the systems of the intermediate time intervals. These are supplemented by the political bounds and other parameters derived from the stakeholder process during the preparation of the NRW H2 Roadmap such as reduction targets for CO2 emissions, energy supply strategy of NRW, network development plans, etc. [15]. Then, in a second step, the cost optimisation of the preceding intervals is carried out, analogously to a forecasting approach, within the set limit values. The basic procedure is summarised in Figure 3.

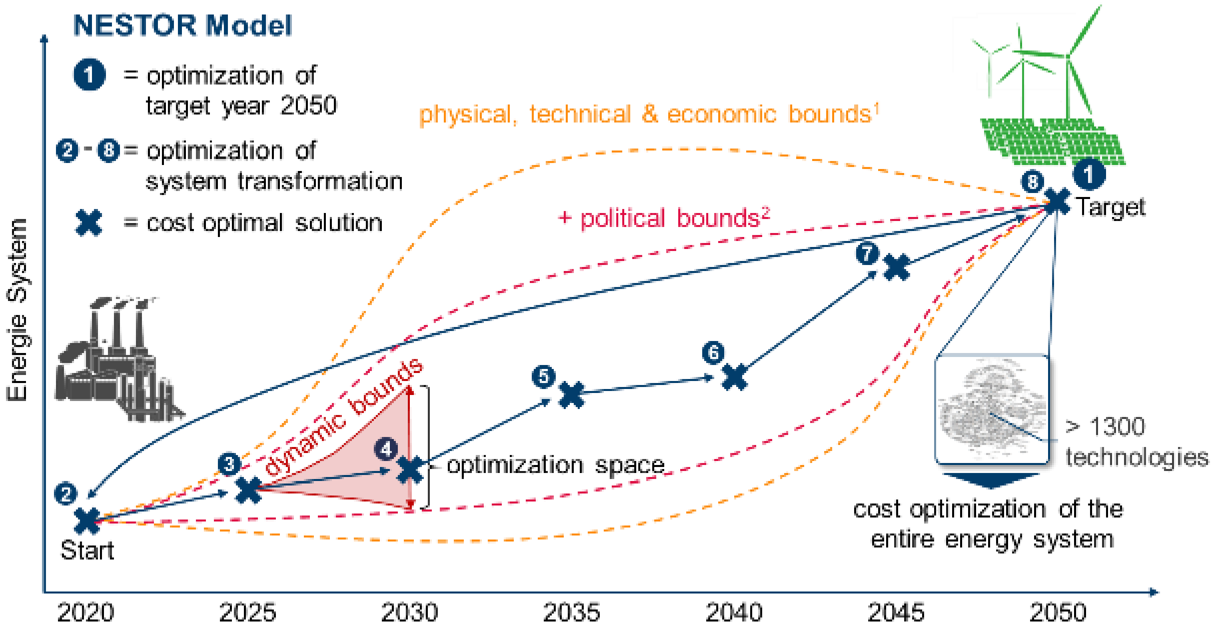

Figure 3: General approach to derive cost-optimal transformation of the entire energy system with the FINE-NESTOR model 1: Scenario "2050Transformation Strategies" [24]. 2: North-Rhine Westphalia H2 Roadmap [15]

We derive generalised market adoption curves for each hydrogen market based on the NRW H_2 Roadmap scenario due to the relative similarity of the energy systems and potentials of hydrogen demand between NRW and the Netherlands (see above). Figure 4 shows the market-specific adoption of hydrogen applications for transportation applications from 2025 to 2050. It can be seen that during the initial phase, up to 2030, train and bus markets experience the most rapid adoption of hydrogen applications. These are followed by hydrogen applications in cars and heavy-duty vehicles (HDVs), which reach similar levels of market adoption as trains and buses by 2040. In the long-term, by 2050, the scenario expects the highest market shares for hydrogen vehicles in the HDV segment where more than three-quarters of the vehicles are fuel cell electric. In the case of passenger cars, buses, and trains, market shares between 40% and 50% are reached by 2050. The majority of the light-duty vehicles (LDV) are expected to be battery electric vehicles due to the typically short daily mileage, and consequently, fuel cell applications would reach only approximately 25% of the market in the long term. For a more detailed assessment of the transport sector and other drive-train types, please refer to the NRW H_2 Roadmap scenario [15].

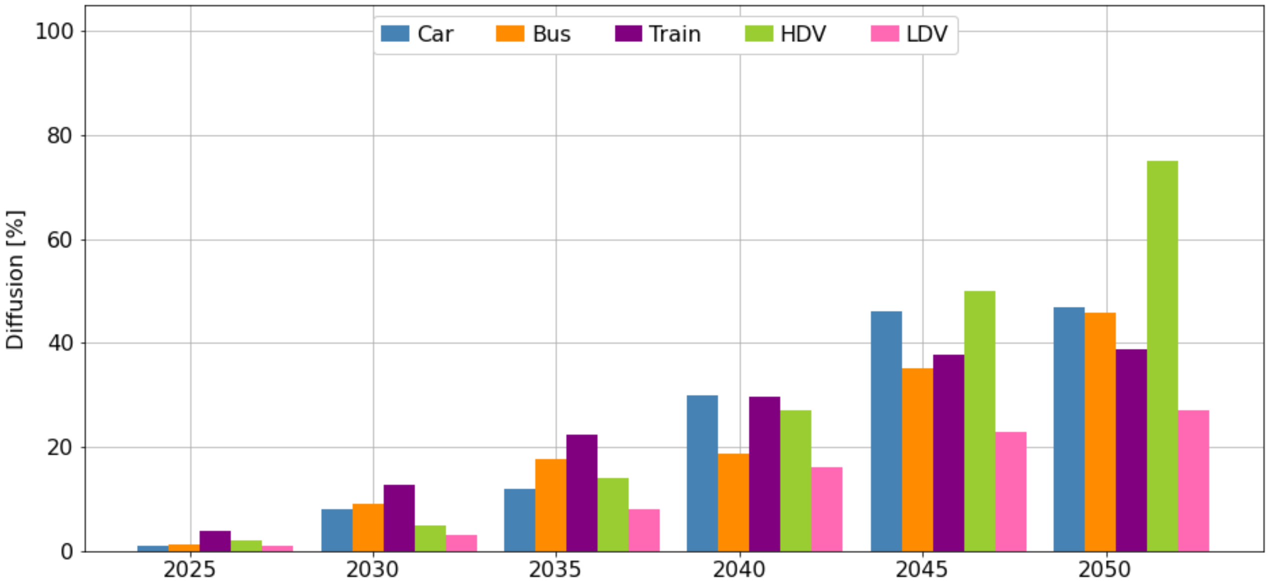

Figure 4: Market diffusion of hydrogen in the transportation sector for the base scenario

In addition to the transportation sector, hydrogen adoption is also expanded in the industry sector. **Figure 5** presents the derived market-specific diffusion curves for ammonia, methanol and steel production. It has to be noted that ammonia and methanol already have a hydrogen demand for feedstock and use reforming of heavy oil or natural gas to produce hydrogen. Therefore, for these markets, the diffusion marks the adoption of GHG-free hydrogen substituting the current production processes. Thus, the substitution of the non-energetic feedstock could be an enabler of an initial hydrogen market development in the industry sector. It can be seen that the adoption

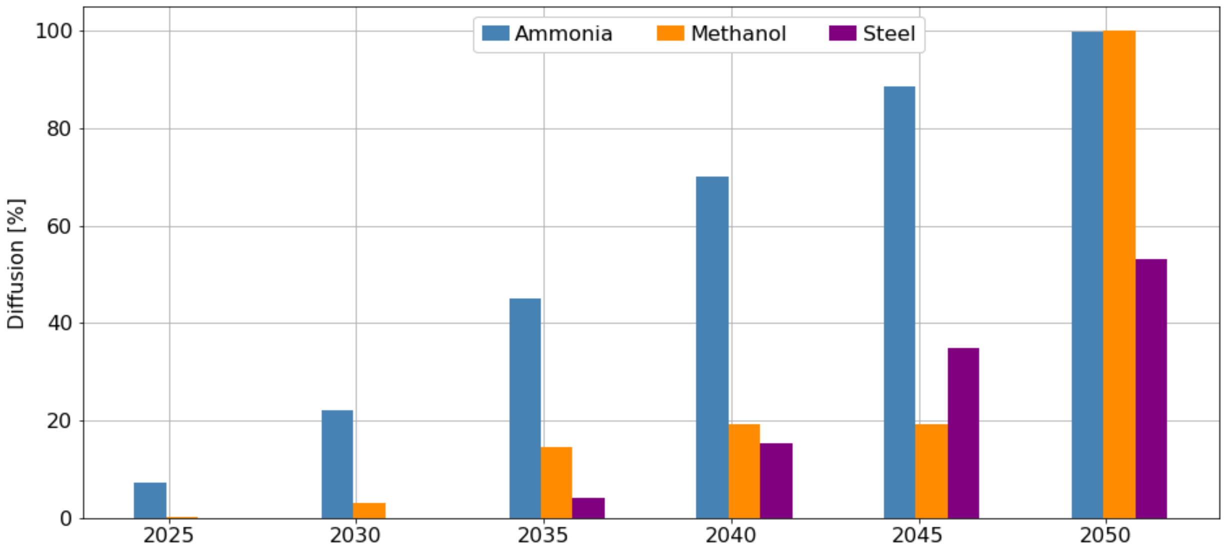

Figure 5: Market diffusion of green hydrogen in the industry sector for base scenario

for ammonia is substantially faster than for methanol. Especially in Germany, a large amount of ammonia is produced via partial oxidation of heavy oil, which is more GHG-intensive than natural gas and substituted first. Moreover, methanol production utilises the by-product heat and CO_2 from the natural gas reformer, making a substitution with GHG-free hydrogen more expensive than is the case for ammonia. In the case of steel production, market diffusion shows the increasing adoption of direct reduction of iron via hydrogen (DRI-H_2) for steel production. While the first steel plants are being converted to the new process between 2030 and 2035, the long-term market adoption reaches over 50% in 2050 as the remaining energy for steel production is derived from electricity and other chemical energy carriers. A more extensive discussion of the industry sector and the role of other energy carriers can be found in the NRW H_2 Roadmap scenario [15].

Further demand options such as hydrogen consumption for process heat or for production of synthetic fuels via power-to-liquids (PtL) are considered in the scenario. However, market diffusion for hydrogen is not displayed at this stage, as both options refer to an extensive set of further uses and applications such as synthetic diesel or synthetic kerosene, as well as non-energetic demand for chemical feedstock, making the market boundaries less defined. In addition, hydrogen use in refineries for desulphurisation of fuels is considered in the analysis, but not displayed in this figure. The demand for fossil fuels in the scenario will decrease significantly up until 2050 and the remaining liquid fuel demand will be replaced by green PtL. According to this, hydrogen demand for desulphurisation of fossils fuels will diminish by 2050.

In addition, in order to better assess the adoption scenarios of the individual markets, these are compared with the data from the literature. The following overview of scenarios (Figure 6) incorporates the relevant European and global market scenarios and adoption targets. In general, it can be seen that various scenarios yield a broad spectrum of hydrogen adoption in 2050, indicating sensitivity to methodology and input parameters of individual scenarios. However, it needs to be pointed out that despite the displayed uncertainty, even the most conservative estimates anticipate the share of fuel cell vehicles in local bus and non-electrified train fleets to achieve 20–25% by 2050, highlighting the role of these markets. Moreover, in the derived scenario, heavy-duty vehicles surpass the anticipated market adoption in other studies. Given the multiple weight classes of the trucks, numerous studies give a market adoption for the overall truck market, which is naturally smaller than market adoption in the individual weight classes. Generally, no scenario anticipates a fleet penetration larger than 20% by 2030, indicating a gradual market adoption after the initial commercialisation phase through 2030. Consequently, this indicates a broader market adoption ten years earlier than later scenarios, highlighting the generally anticipated period of a decade to introduce the technology.

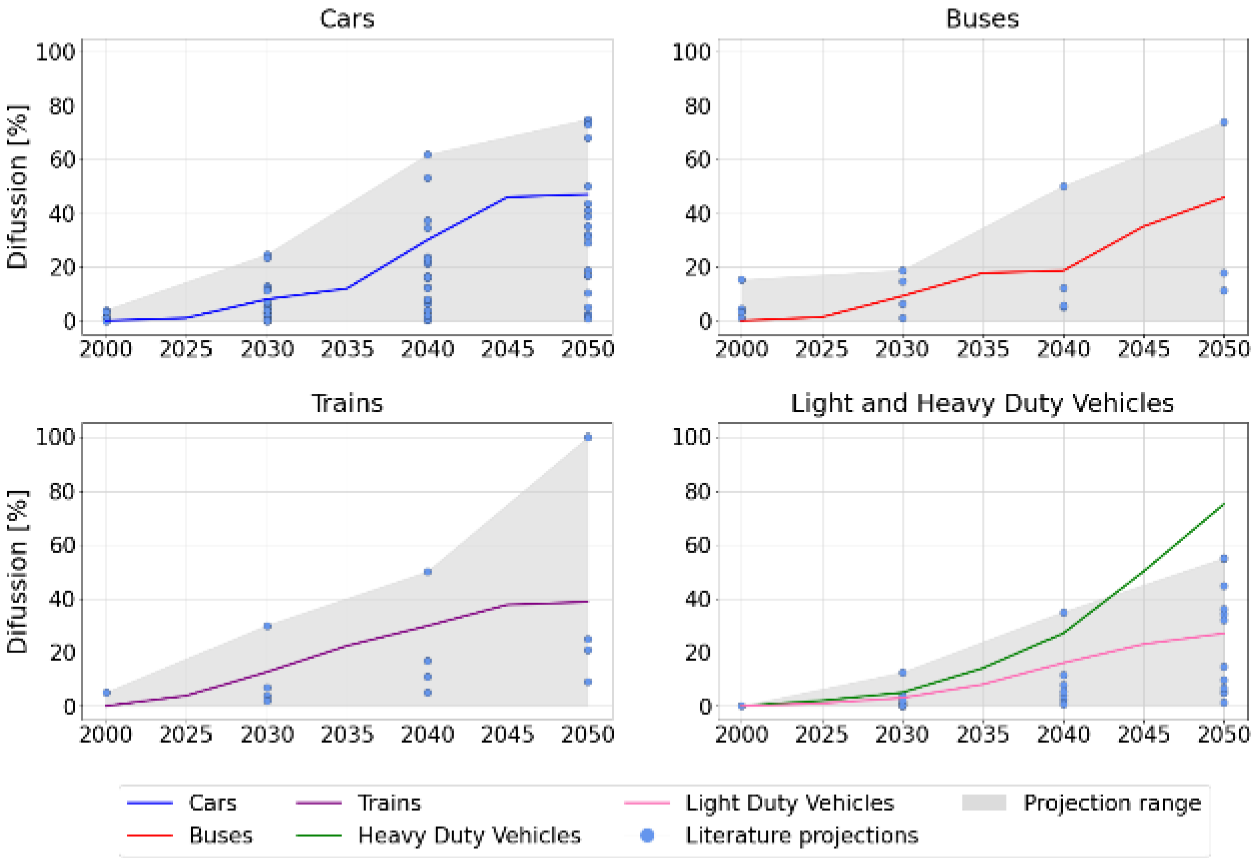

Figure 6: Data for hydrogen penetration scenarios from 2020 to 2050 [1, 8, 19, 20, 23, 29–54]. Lines indicate the penetration for the individual markets in the reference scenario. Grey area portrays the range provided in the analysed literature.

3.3. Demand scenario

After technology availability is assessed and the market adoption scenarios for each market segment are set, the development of the hydrogen markets can be evaluated. It should be emphasised that the results are scenarios and not forecasts. Figure 7 shows the development and the structure of external hydrogen demand in both the Netherlands and North Rhine-Westphalia. For the industry sector, the following analysis considers only the share of hydrogen demand that does not occur as a by-product at the industrial site or is not produced at the site itself, thus onsite production as a by-product or onsite electrolysis is subtracted from the total demand to derive the quantities relevant for the development of delivery infrastructure. As previously discussed, both regions have a comparable overall potential for transportation and industrial demand, as well as many similar features regarding the structure of these markets. Henceforth, given that the same hydrogen adoption was assumed, both regions develop in a comparable manner and total size of the demand, surpassing their current grey hydrogen demand between 2035 and 2040 in NRW and the Netherlands, respectively.

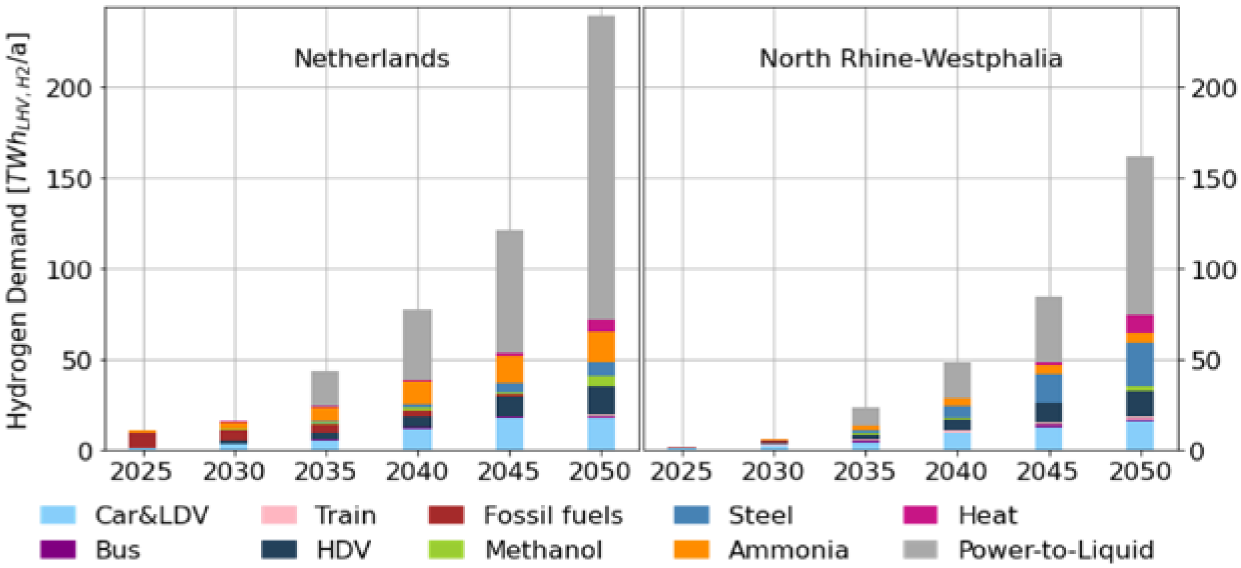

Figure 7: Development of external hydrogen demand and its structure for the Netherlands and North Rhine-Westphalia from 2025 to 2050

A common market for both NRW and the Netherlands boosts potential hydrogen demand and can increase security of supply, while reducing the risk of stranded assets.

The structure of energy demand in NRW and the Netherlands for future hydrogen demand will be dominated by industry, especially the chemical and petrochemical industry, refineries, and high share of urban areas with high road, rail, and aviation fuel demands. In addition, the assumed demand scenarios consider non-energetic use by domestic green naphtha for chemical feedstock and products. The assumed hydrogen demand especially for producing PtL as transportation fuel and chemical feedstock is therefore different in comparison to scenarios with a national and not NRW focus, for example, in studies by Sensfuß, F. et al[3] and DENA[4]. These scenarios assume lower shares of hydrogen demand in transportation and PtL. In the assumed scenarios the hydrogen demand starts to play a major role beginning in 2035 (NRW: 10 TWh, NL: 19 TWh), as hydrogen is consumed to produce various PtL products such as synthetic diesel and kerosene for road and air transportation, as well as for synthetic naphtha production required as feedstock in the chemical industry (see Figure 8).

[3] Sensfuß, F. et al: Langfristszenarien für die Transformation des Energiesystems in Deutschland, Study on behalf of Federal Ministry for Economic Affairs and Energy, Germany; https://www.bmwi.de/Redaktion/DE/Downloads/B/berichtsmodul-3-referenzszenario-und-basisszenario.pdf

[4] Deutsche Energie-Agentur GmbH (Hrsg.) (dena, 2021). „dena-Leitstudie Aufbruch Klimaneutralität. https://www.dena.de/fileadmin/dena/Publikationen/PDFs/2021/Abschlussbericht_dena-Leitstudie_Aufbruch_Klimaneutralitaet.pdf

A higher hydrogen demand for PtL is also allocated to the refineries in the Netherlands, rather than in NRW, given the higher capacity there. Given the similarity of the regions, other sectors such as industry, including methanol, ammonia, steel and process heat production, as well as the transportation sector have a comparable overall size. It can be seen that demand in both regions up to the year 2030 is primarily driven both by the transportation sector (NRW: 4 TWh, NL: 5 TWh) and the substitution of existing hydrogen demand in the refineries for processing of fossil fuels as well as in ammonia production (NRW: 2 TWh, NL: 11 TWh). In contrast, hydrogen demand for steel production and process heat plays a more important role after 2035 and 2045, respectively (see Figure 5 for comparison). This highlights the importance of substituting the existing hydrogen demand in the industrial sector during the ramp-up of a clean hydrogen market. In 2050 overall demand for hydrogen is anticipated to reach up to 162 TWh and 239 TWh in NRW and the Netherlands, respectively.

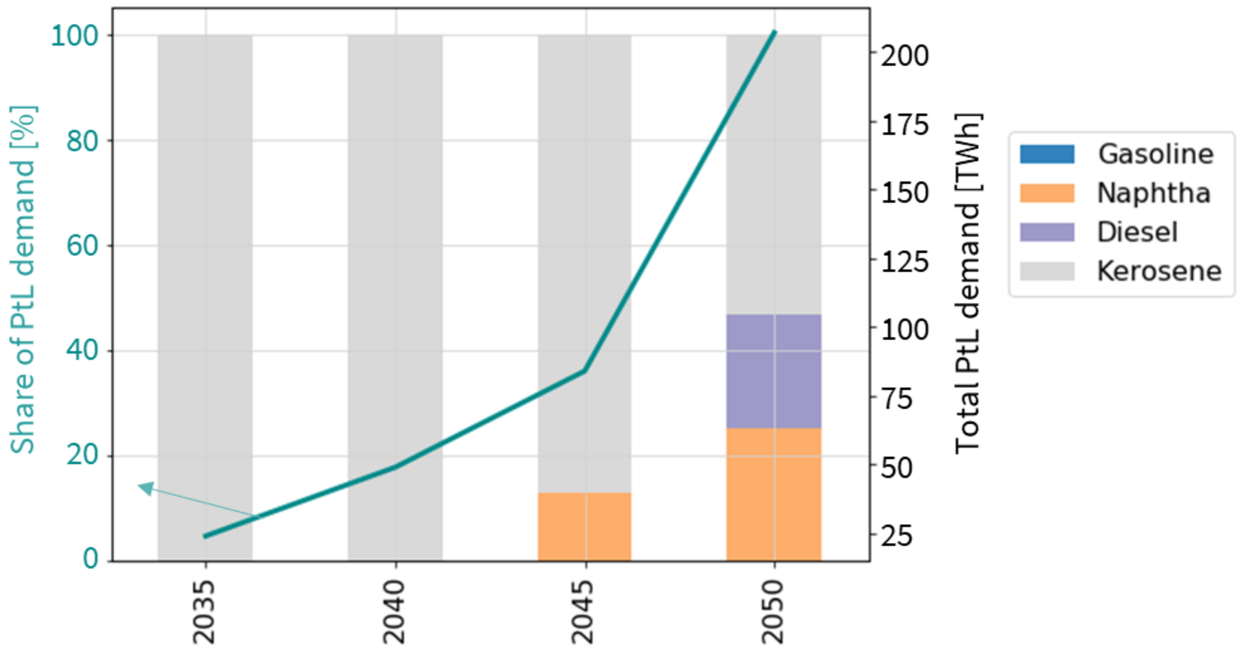

Figure 8: Development of the structure of hydrogen demand for PtL in NRW and the Netherlands from 2035 to 2050

The highest concentration of hydrogen demand can be observed along the coastal regions in the Netherlands, as well as South Netherlands and the western part of NRW, reaching 6.2 TWh in Rotterdam, 3.9 TWh in Zeeland and 1.8 TWh in Maastricht as well as 1.6 TWh in Duisburg regions (see Figure 9). These are the same regions as the identified areas for allocating the current hydrogen and encompassing the major population centres in the Netherlands and NRW. The lowest demand is anticipated in the rural areas in the south-east of NRW with 0.5 TWh. Thus, all regions surpass the demand of 0.5 TWh p.a., which is an approximate demand threshold for cost-competitiveness of a long-distance pipeline to trailer transport [24] [25]. If delivery is centralised, a hydrogen pipeline may offer a cost-effective means of hydrogen transport in 2030 already.

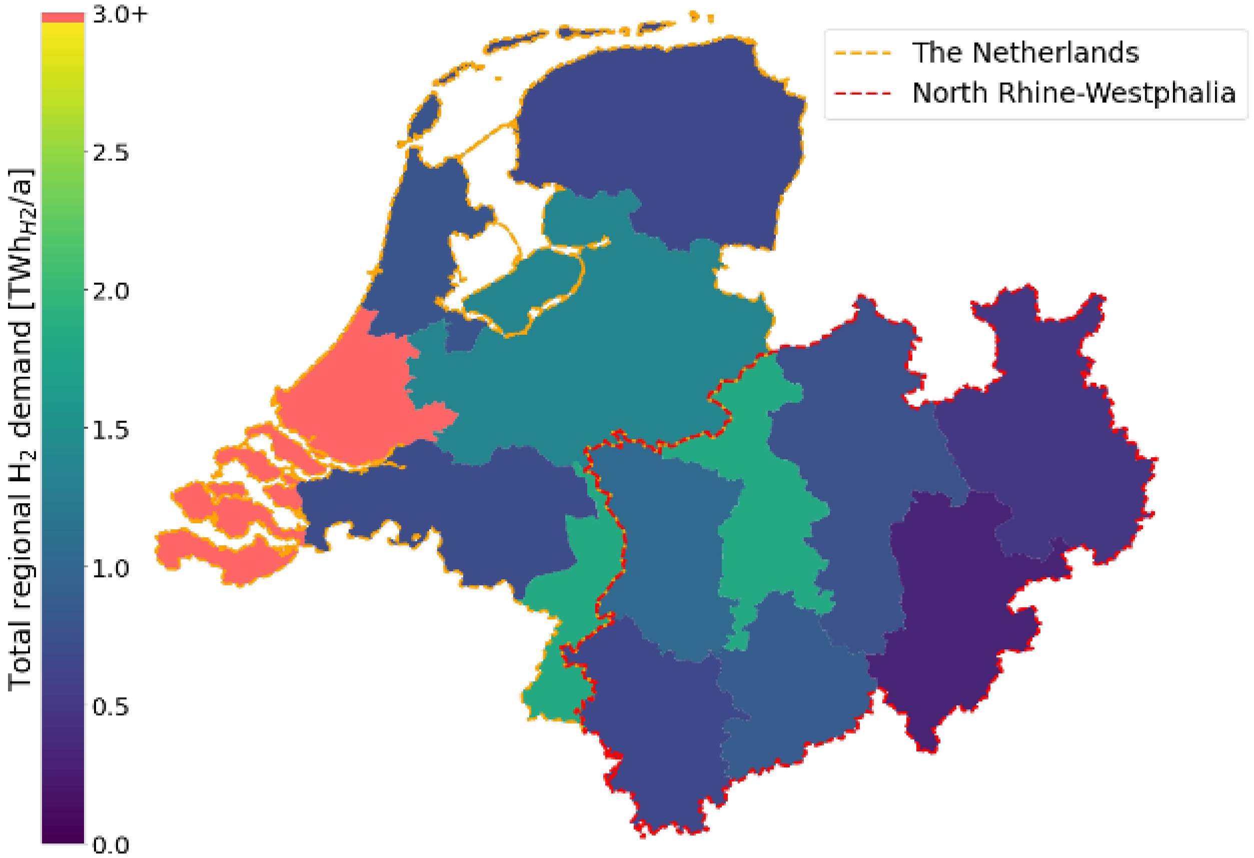

Figure 9: Regional allocation of external hydrogen demand in the Netherlands and North Rhine-Westphalia in the year 2030

A green hydrogen demand of about 6 TWh is anticipated in NRW for 2030, without taking into account current grey industrial demand. 73.8% of hydrogen demand can be allocated to the transportation sector and 20.2% to the industrial sector. The remaining demand relates to the external clean hydrogen demand in the refineries. In contrast to NRW, the demand for hydrogen in the Netherlands would reach 15.5 TWh. Moreover, with 41.7% and 28.0%, the demand share of refineries and industry in the Netherlands is larger, as clean hydrogen is used earlier in those areas than in steel production, which assumes a dominant position in NRW (see Figure 10).

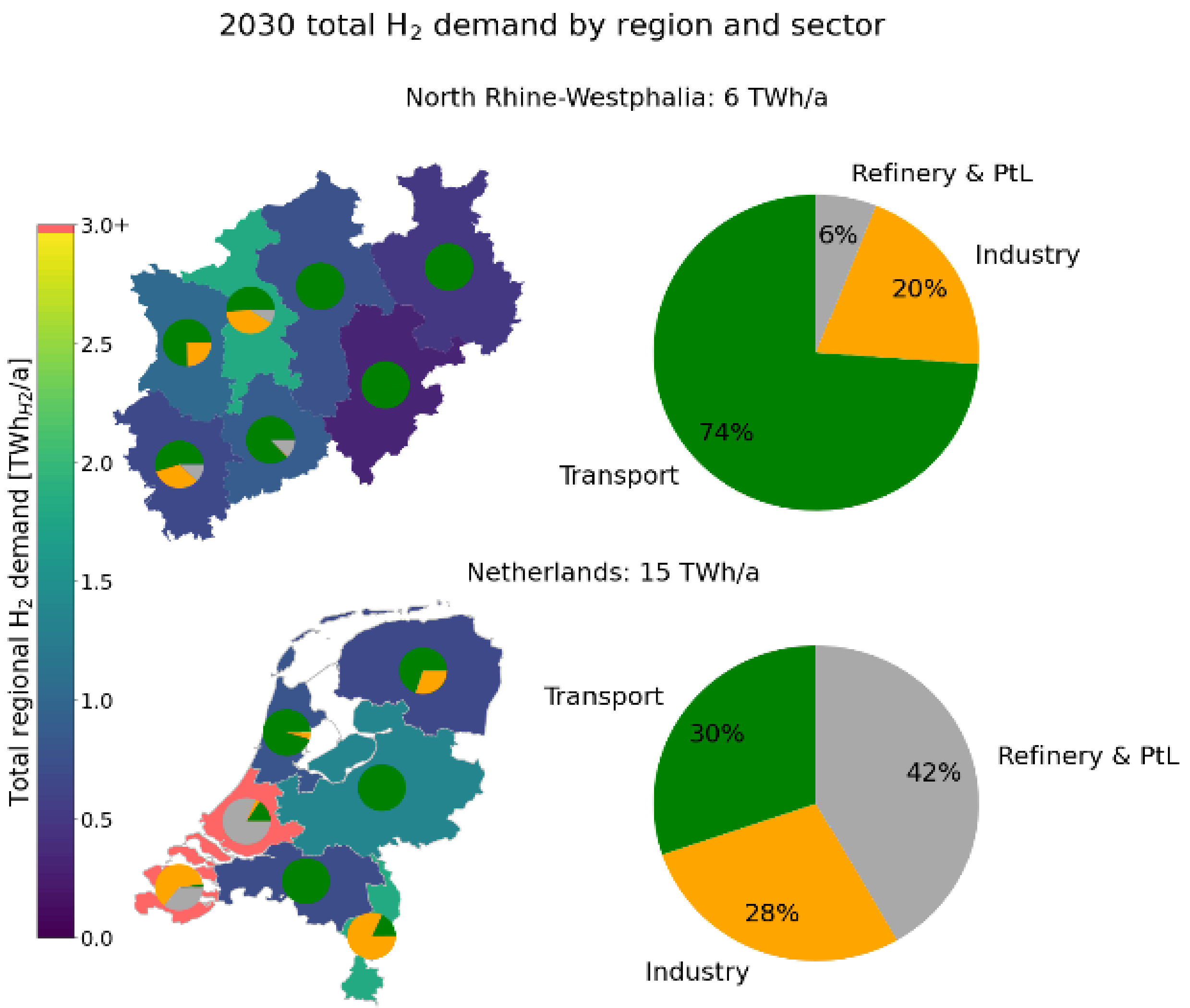

Figure 10: Overall and regional structure of external hydrogen demand in NRW and the Netherlands for 2030 (possible deviation from 100% due to rounding errors)

Hydrogen demand in the transportation sector of NRW adds up to about 4 TWh in 2030 (see Figure 11). The largest share of ca. 60% is for passenger cars. In 2030, HDVs already account for 25% of hydrogen demand in the transportation sector, with a strong upward trend until 2050. Accordingly, demand is rather evenly distributed among the regions in western and central NRW. In the case of the Netherlands, overall demand reaches ca. 5 TWh, and the structure of demand is comparable with NRW. However, due to the smaller number of trains and busses, these markets play a somewhat smaller role in the overall hydrogen demand for transportation. Demand is mainly located in the western and central regions of the Netherlands, which encompass the majority of the Dutch population and vehicle fleet.

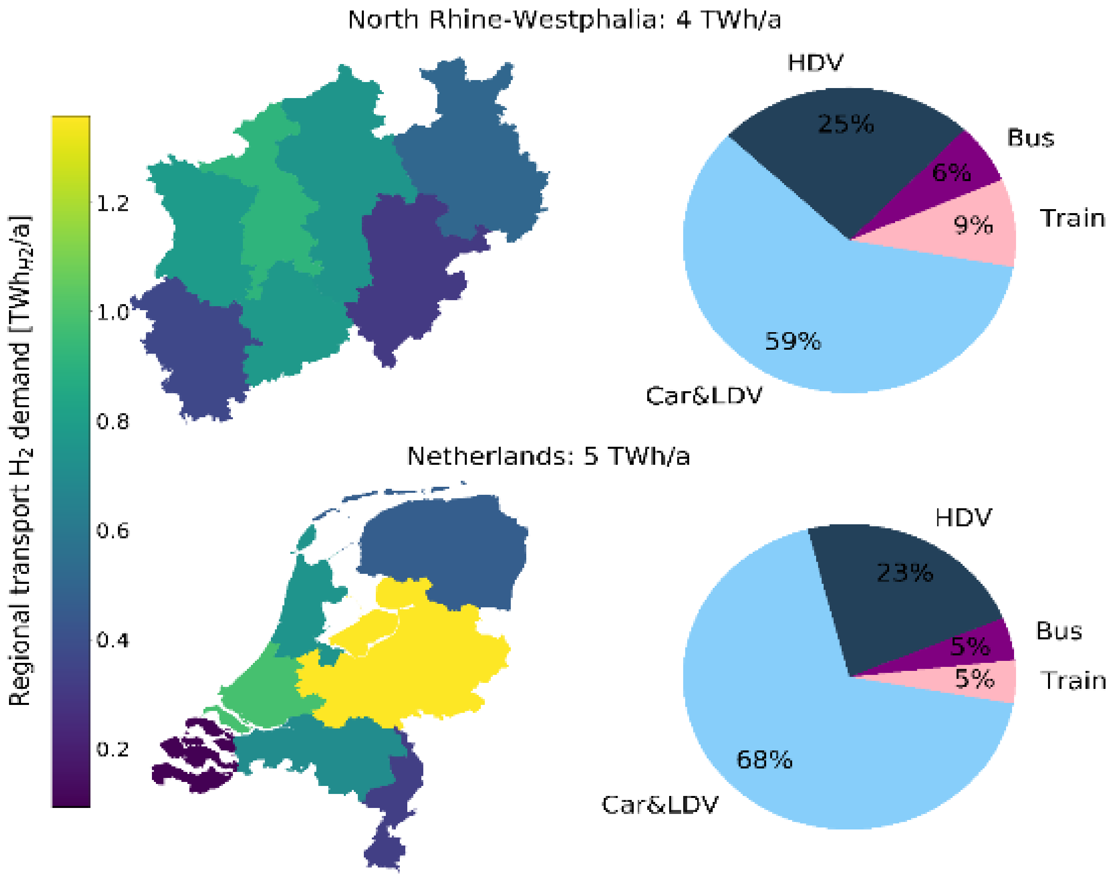

Figure 11: Overall structure and regional allocation of hydrogen demand of the transport sector in NRW and the Netherlands for 2030 (possible deviation from 100% due to rounding errors)

As for the industrial sector in NRW, demand reaches ca. 1 TWh in 2030, and the demand centres correspond to the chemical industry and refinery sites as a wider adoption of hydrogen is yet to take place (see Figure 12). In general, the industrial sector's hydrogen demand in 2030 is distributed among only a few selected counties. This can be justified by the fact that the use of external hydrogen is initially only applied in basic chemicals, where hydrogen is already used, for example, in ammonia and methanol production. Similarly, external industrial demand in the Netherlands (4 TWh) is primarily driven by the chemical sector (including ammonia and methanol), highlighting the importance of the low-hanging fruits during market rollout in the industrial sector.

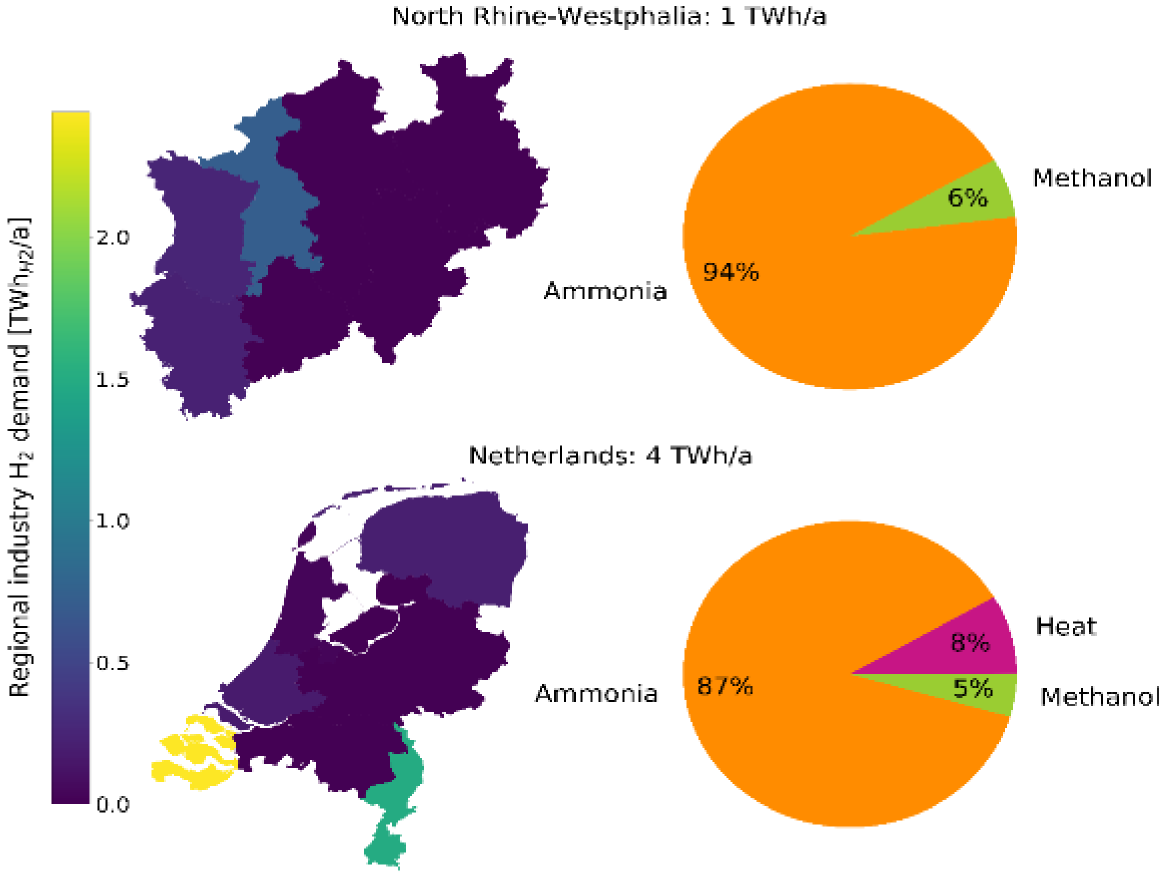

Figure 12: Overall structure and regional allocation of external hydrogen demand of the industry sector in NRW and the Netherlands for 2030 (possible deviation from 100% due to rounding errors)

From a long-term perspective, total annual hydrogen demand in the final energy sector in NRW reaches ca. 162 TWh in 2050, excluding the conversion sector (see Figure 13). In contrast to 2030 (dominance of transportation demand with 74%), 26% and 20% of this demand consist of industrial and transportation demands, respectively. The other 54% is used for PtL production at the refinery locations. This result demonstrates the strategic role of industrial and especially PtL hydrogen demand in NRW, which will significantly influence the design of hydrogen supply in the long term. Hydrogen demand is concentrated primarily in the western regions of NRW. In the case of the Netherlands, total demand in 2050 reaches 239 TWh and, due to the prominent role of PtL (70%) and concentration of the refineries in the West Netherlands, overall hydrogen demand is more concentrated than in NRW (see Figure 8 for PtL demand structure). The remaining 30% of demand are almost evenly split between industry and transportation.

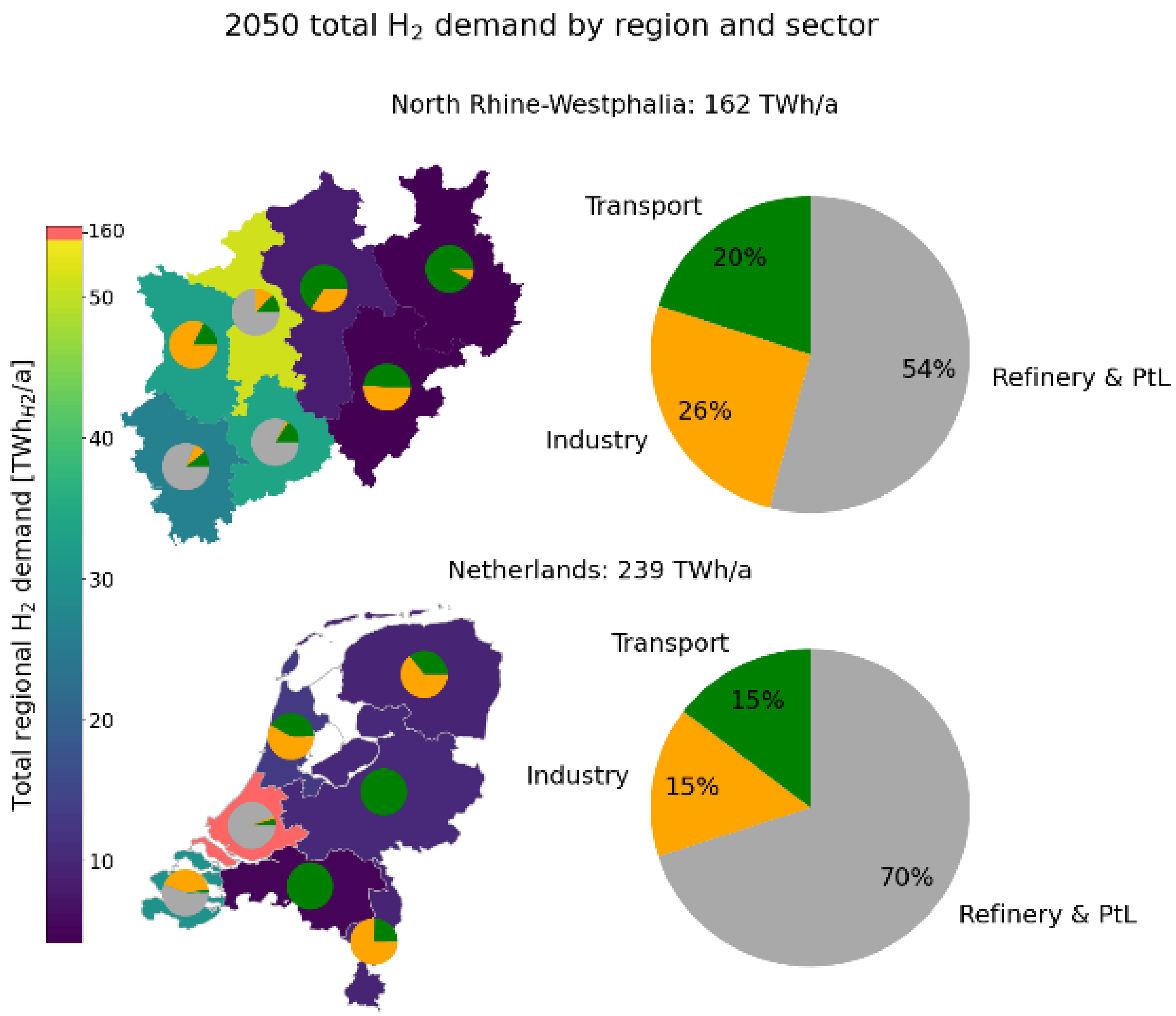

Figure 13: Overall and regional structure of external hydrogen demand in NRW and the Netherlands for 2050 (possible deviation from 100% due to rounding errors)

Transportation demand in NRW reaches 32 TWh in 2050. In contrast to 2030, hydrogen demand for transportation in 2050 is dominated primarily by the demand for HDVs (44%) and passenger cars (48%), while trains and buses will play a minor role (about 8%) (see Figure 14). Nevertheless, as of today, they are essential for increased infrastructure utilisation and thus for economic implementation, especially in the introductory phase. In contrast to industrial consumption, demand for transportation is much more evenly distributed among the regions. One of the most important reasons for this is a high share of HDVs. Thus, high demand for hydrogen is also expected in less urbanised regions. A very similar picture develops in the Netherlands, where, at an overall transport demand of 35 TWh, 96% of transportation demand is governed by passenger cars and HDVs. With the majority of the population and vehicle fleet concentrated in the eastern and western Netherlands, these regions have the highest share of transportation demand in 2050.

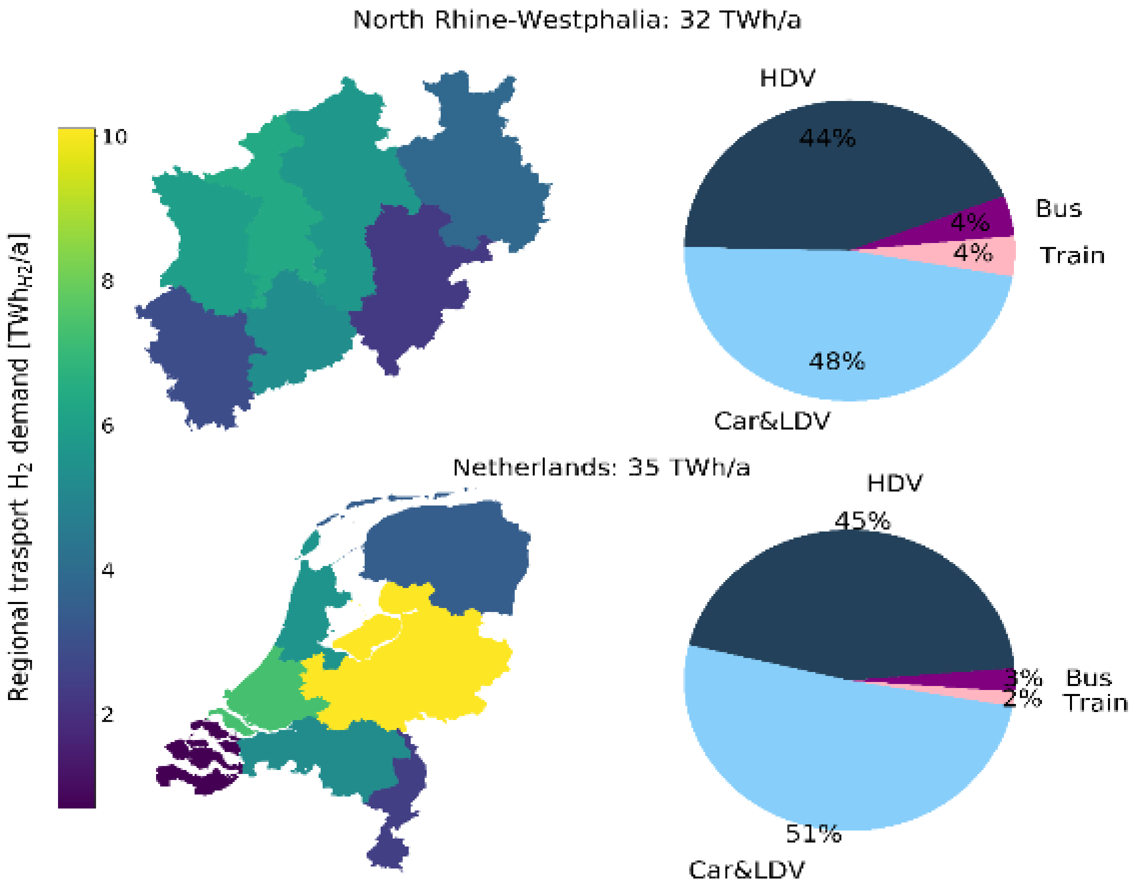

Figure 14: Overall structure and regional allocation of hydrogen demand of the transportation sector in NRW and the Netherlands for 2050 (possible deviation from 100% due to rounding errors)

Industrial demand for hydrogen in NRW in 2050 reaches ca. 42 TWh and is dominated by steel production (around 58%) (see Figure 15). This is followed by high-temperature process heat for industrial furnaces or cement production and ammonia as well as methanol production with approximately 24%, 12% and 6%, respectively. In addition, about 8% of industrial demand is used for industrial furnaces. With over 25 TWh, the focal point of industrial demand for hydrogen in NRW is found in the western part of the region and particularly in the Rhine-Ruhr region with its prevalence of steel and chemical plants. However, the demand of ca. 37 TWh in the Netherlands for industry is substantially more decentralised, and two-thirds of demand revolves primarily around the chemical industry, such as ammonia and methanol production, with 47% and 17%, respectively. In contrast to NRW, demand for steel and process heat in the Netherlands makes up only ca. 19% and 17% of total demand, respectively. Consequently, a more evenly distributed supply infrastructure for industry will be required in the Netherlands.

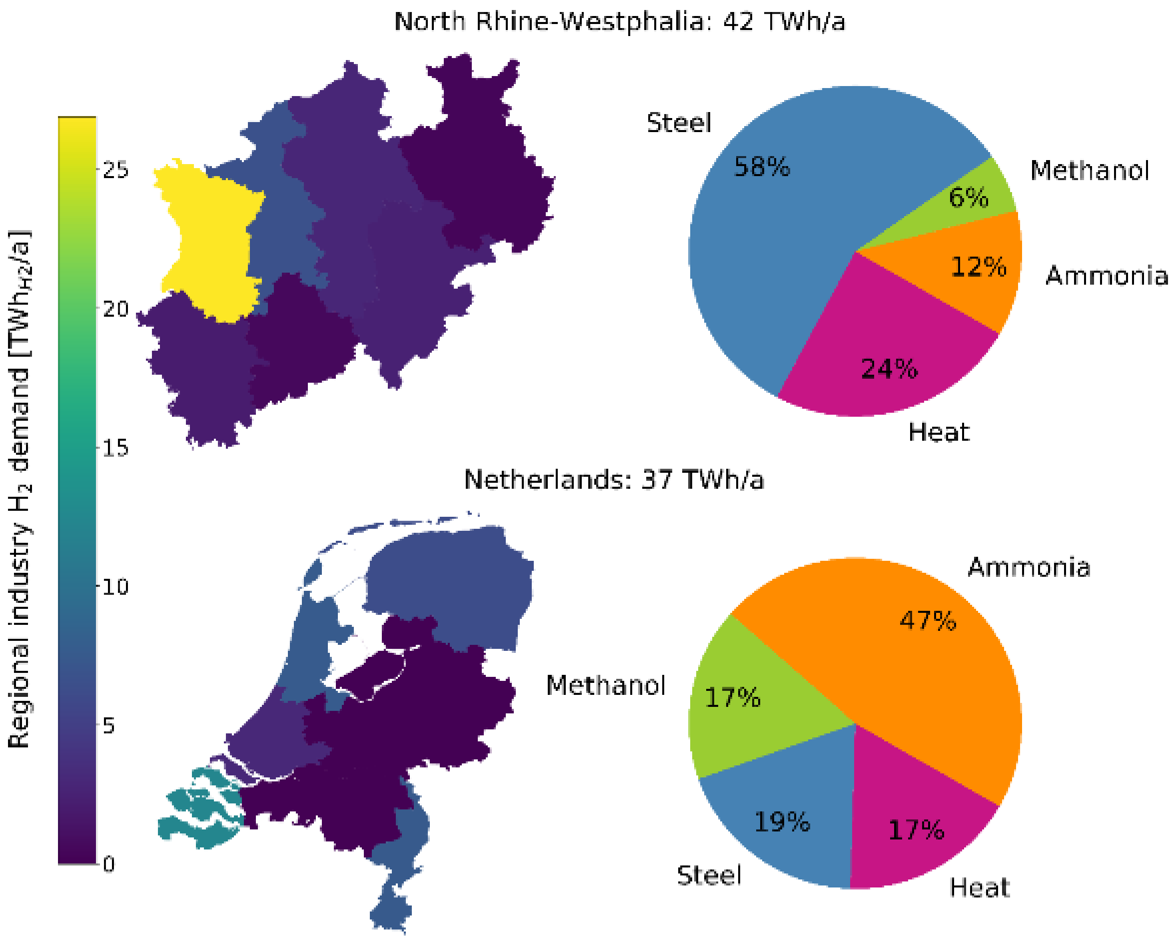

Figure 15: Overall structure and regional allocation of external hydrogen demand of the industry sector in NRW and the Netherlands for 2050 (possible deviation from 100% due to rounding errors)

4. Hydrogen production from offshore wind

Green hydrogen supply in this study presumes a process of electrolysis of fresh or desalinated sea water, powered by renewable electricity from offshore wind. Practical experiences in large-scale green hydrogen production are yet to be documented. Therefore, any scenario of potential utilisation needs a conceptual energy system, constrained by various boundary conditions. In the case of potential green hydrogen production in the Dutch and German North Sea, national targets for offshore wind and green hydrogen production are considered, as well as distinctive supply chain concepts for hydrogen production, which is described in Section 4.1. In this regard, an assessment of offshore wind potential in the Dutch and German North Sea, resulting in electricity generation with hourly resolution, is performed and described in Section 4.2. Furthermore, Section 4.3 presents hydrogen production scenarios. These include hourly time series of produced hydrogen for various combinations of possible operating modes of electrolysers and assumed delivery points to the onshore hydrogen pipeline backbone. In the same section, an analysis of hydrogen production costs is conducted and the resulting levelised costs of hydrogen are presented. Finally, an assessment of CO_2 emissions savings by utilising green hydrogen is performed, as described in Section 4.4.

4.1. Supply chain concepts

In this study, hydrogen production was assessed for two distinctive infrastructure configurations, here named “supply chain concepts” (see Figure 16).

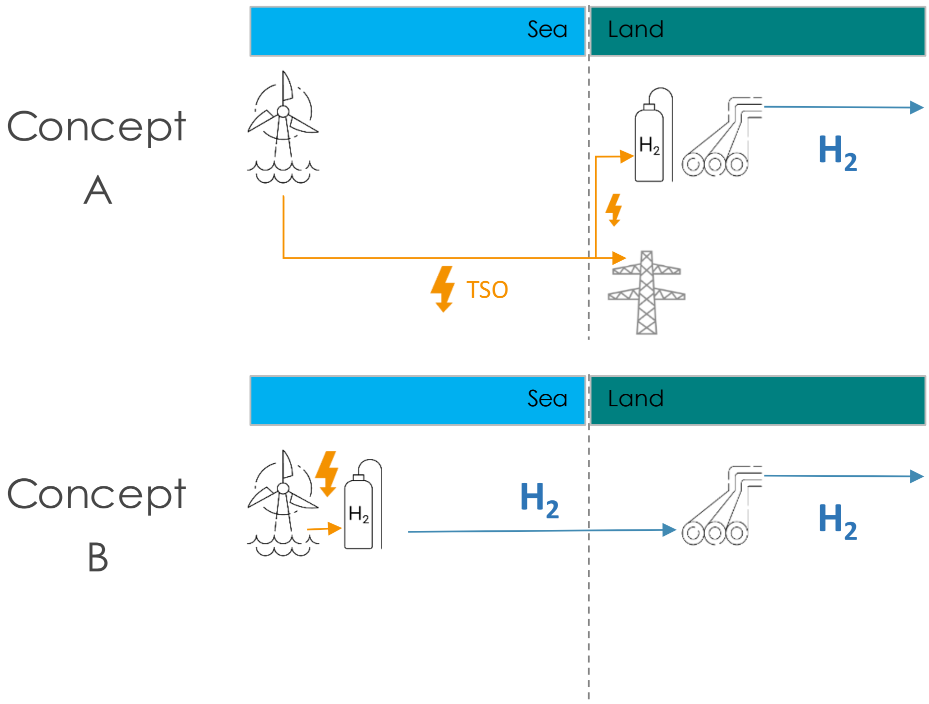

Figure 16: Configuration settings of the supply chain concepts for hydrogen production (own analysis)

- Concept A – Onshore electrolysers: The electrolysers are installed on land (along the coast) and powered by electricity from offshore wind farms via a grid connection. Produced hydrogen is fed into an onshore hydrogen backbone pipeline (see Section 5).
- Concept B – Offshore electrolysers: The electrolysers are directly connected to the offshore wind farms and are located at offshore platforms together with sea water desalination facilities. Produced hydrogen is fed into an offshore hydrogen pipeline, which is connected to an onshore hydrogen backbone pipeline.

4.2. Offshore wind potential assessment

Modelling of the development of offshore wind energy in the Dutch and German North Sea as well as modelling of the corresponding generation time series is based on available data for offshore wind energy areas, the latest plans for wind park project development and currently operational wind parks. Analysis was performed in cooperation with the Fraunhofer Institute for Energy Economics and Energy System Technology (FIEE), which carried out the required modelling. Detailed methodology and assumptions on technological and operational settings of wind parks and wind turbines can be found in Appendix B1. Hourly wind speed data from a numerical weather model (COSMO-REA6, Deutscher Wetterdienst) for the historical year 2012[5] is used as the meteorological input.

4.2.1. Areas for offshore wind energy

Based on available information and assumptions (see Appendix B1), designated priority and reserved areas as well as possible additional areas for offshore wind production were determined for the German North Sea (see Figure 17).

Area development in the German North Sea in stages takes into account the following:

- Operational wind parks
- Planned development according to the area development plan and the spatial development plan [27]: first concrete projects/planned clusters, later via the LCOE model6 [26]
- By 2030: priority areas from the area development plan,
- By 2040: reserved areas according to the BSH with sequence derived from the LCOE model
- Additional areas in the shipping route (SN10) are included but developed with a lowest priority

Similarly for the Dutch North Sea, area development in stages is modelled according to:

- Areas from scenario IV “Sustainable Together” from the study “The Future of the North Sea” [28]
- Operational wind parks
- By 2025: tenders for wind farm zones as published by the Netherlands Enterprise Agency [29]
- By 2030: ca. 11.5 GW according to the PBL road map [28]

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[5] This year is also the basis for the FIEE European energy scenario and is used as a base year in the grid development plans by the German transmission system operators.

[6] starting with the area with the lowest levelised cost of electricity (LCOE) until the desired capacity is reached (for details on the LCOE model, see Appendix B3)

- Long term: full development of PBL scenario IV "Sustainable Together" [28]

Resulting offshore wind development in the first (2025) and the last reference year (2050) are shown in Figure 17**.**

4.2.2. Electricity generation time series

The numerical weather model COSMO-REA6[7] provides meteorological data to determine an electricity generation time series. The characteristic power curve is determined synthetically from the assumptions for the plant configuration, in particular taking into account the specific power. Subsequently, a smoothed power curve is obtained (see Appendix B1). The wind park shading (wake losses) is taken into account by using an empirically derived, wind speed dependent shading curve (also in Appendix B1). Finally, the electricity generation time series are obtained by multiplying hourly wind speed data[8], corrected by wake losses, with the given power curve and the installed capacity. The resulting installed capacity and energy yields for the German and Dutch North Sea are shown in Figure 19 and Figure 20, and detailed information on resulting installed capacity of the offshore wind parks, energy yield, average capacity factor and average full load hours for each reference year is available in Table 8 of Appendix B1. It should be noted that in the case of the German North Sea, presumed installed capacity does not include the

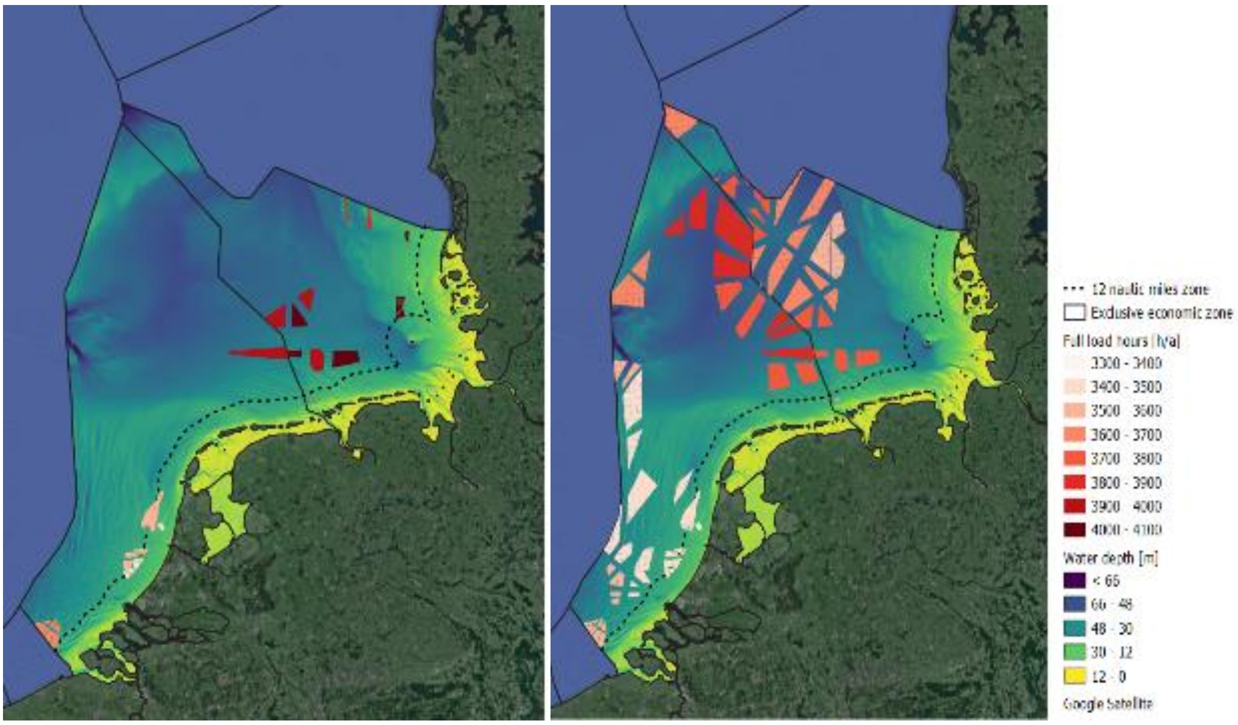

Figure 17**:** Map of the developed offshore wind parks and resulting full load hours in 2025 (left) and 2050 (right). Note that the Netherlands' wind farm search areas towards 2050 are under development and will most likely not match the exact locations presented here

[7] COSMO-REA6 is the regional reanalysis tool from the Germany's National Meteorological Service, the Deutscher Wetterdienst (DWD)

[8] Wind speeds at hub height are calculated from flanking height levels by logarithmic interpolation

German Baltic Sea, which also contributes to offshore wind expansion targets of 20 GW by 2030 and 40 GW by 2040 according to the Wind Energy at Sea Act [85].

Wind power generation in Germany and the Netherlands in 2050

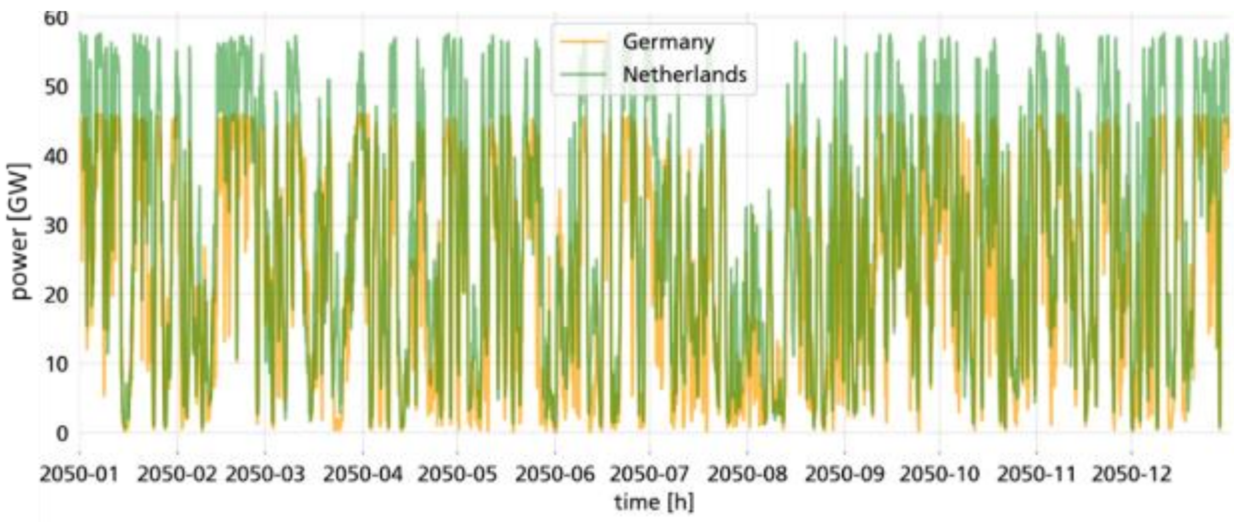

Figure 18: Aggregated electricity time series from offshore wind power in the Dutch and German North Sea in 2050 (own representation)

Under the meteorological conditions of the historical year 2012, up to 195.5 TWh of electric energy are generated in the German North Sea in 2050, and 249 TWh in the Dutch North Sea, respectively. The resulting aggregated electricity time series from offshore wind power in Germany and the Netherlands in 2050 are shown in Figure 18.

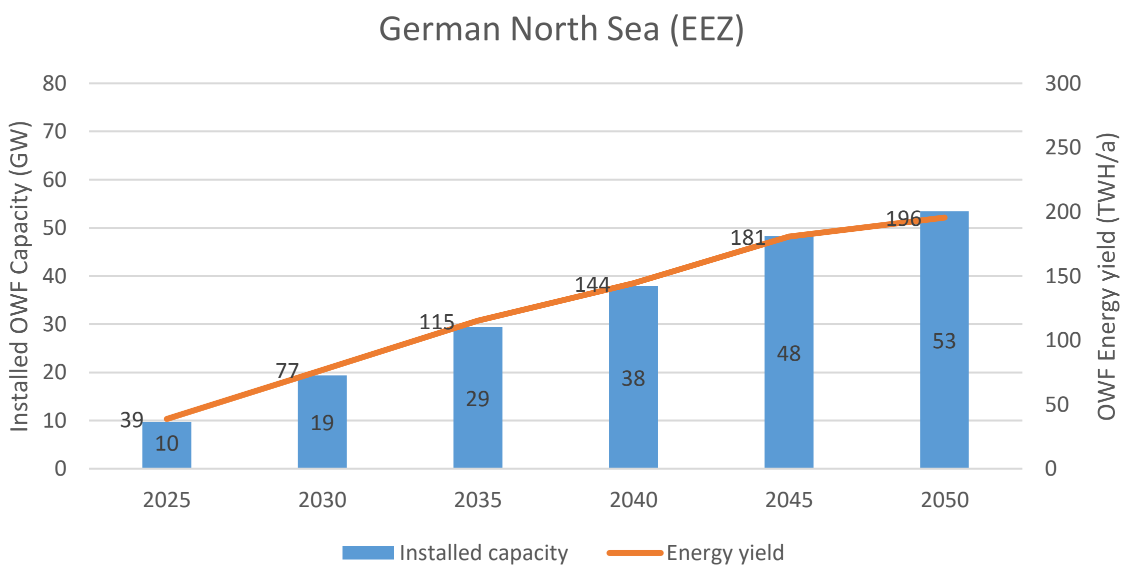

Figure 19: Installed capacity and energy yield of offshore wind in the German North Sea

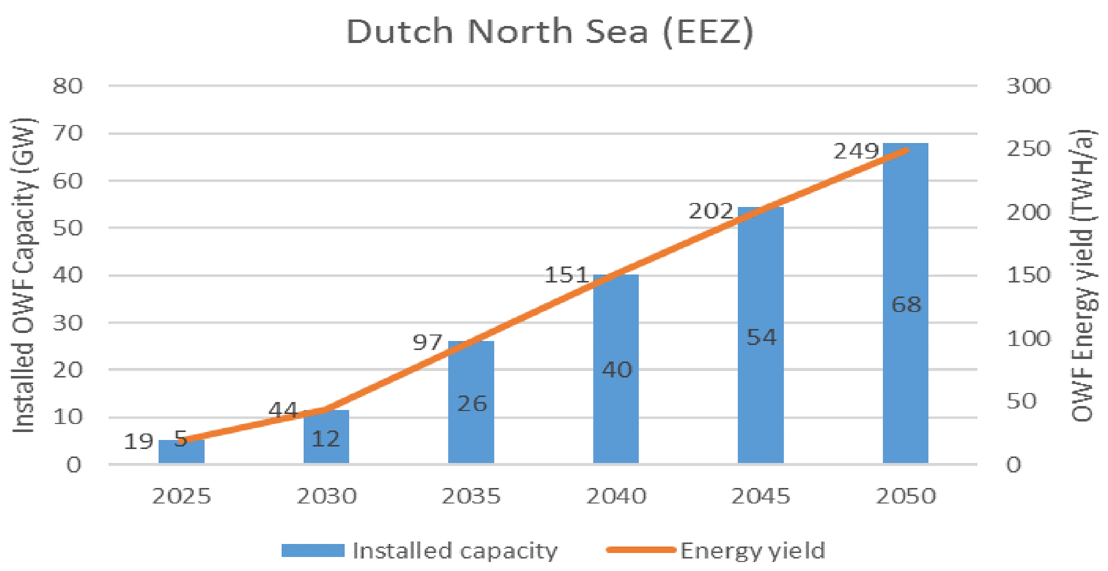

Figure 20: Installed capacity and energy yield of offshore wind in the Dutch North Sea

4.3. Hydrogen production scenarios

The following hydrogen production scenarios from offshore wind are being developed by taking into account supply chain concepts, the offshore wind potential assessment, possible deployment roadmap for the electrolysis capacity as well as the hydrogen production scenarios and sub-scenarios. Aim of the scenarios is to analyse different approaches and their implications on scale, costs and timing of hydrogen production from the EEZ of the Netherland and Germany in the North Sea. The scenarios provide a basis to analyse implications on import, transport and storage needs. The scenarios neither take into account the existing political goals and framework for utilisation of offshore wind potential for the provision of renewable electricity from offshore wind, nor do they analyse a systemic optimum for the right share of offshore wind potential to be used for renewable electricity in relation to renewable hydrogen. In this respect the scenarios should be considered as exploratory scenarios for hydrogen production from offshore and not as optimal scenarios or realistic forecasts.

The analysis was performed in cooperation with the Fraunhofer Institute for Energy Economics and Energy System Technology (FIEE), which carried out the modelling work.

4.3.1. Scenarios and deployment roadmap

A starting point in analysing potential ways to produce hydrogen from offshore wind was to explore several conceivable approaches of coupling offshore wind production with operation of onshore and offshore power-to-gas facilities. For each of the two supply chain concepts, two different operating modes for the electrolysers are considered. By applying each scenario to assumed delivery locations to the onshore hydrogen backbone, four sub-scenarios in the case of Germany and eight sub-scenarios in the case of the Netherlands were modelled, as depicted in Table 3.

Table 3: Overview of the hydrogen supply scenarios

Supply chain concept	Scenarios	Sub-scenarios	
	Operating mode of electrolysers (offshore power source)	**Feed-in points Germany**	**Feed-in points Netherlands**
Concept A (onshore electrolysis)	**A1** - surplus energy use (DE zones 1–5 / NL clusters 1–6)	DE A1 Emden	NL A1 Rotterdam NL A1 Groningen
	A2 - fixed percentage of electricity from offshore wind (DE zones 1– 5 / NL clusters 1–6)	DE A2 Emden	NL A2 Rotterdam NL A2 Groningen
Concept B (offshore electrolysis)	**B1** offshore electrolyser, no grid connection (DE zones 4, 5 / NL clusters 3, 4, 5)	DE B1 Emden	NL B1 Rotterdam NL B1 Groningen
	B2 additional grid connection of max. 2 GW per zone / cluster (DE zones 4, 5 / NL clusters 3, 4, 5)	DE B2 Emden	NL B2 Rotterdam NL B2 Groningen
Mixed Concept (onshore and offshore electrolysis)	**A2 near-B1** = A2 scenario restricted to near to the shore DE zones 1, 2, 3 (Emden), NL clusters 1, 2 (Rotterdam) and 6 (Groningen), aggregated to B1 scenario	DE A2 near-B1 Emden	NL A2 near-B1 Rotterdam NL A2 near-B1 Groningen

For all scenarios, it is assumed that a significant part of offshore wind installations will be grid-connected. In this context simplified assumptions are made that a maximum of 24 GW of offshore wind power is connected to the onshore electricity grid on the German side in 2050, and a maximum of 26 GW on the Dutch side. In the case of the Netherlands, a conservative scenario for offshore wind assumes expansion up to 11.5 GW by 2030 and 26 GW by 2050 [35]. In both cases, these figures fit a recent detailed Fraunhofer IEE 100% RE scenario analysis for Germany and Europe. The remaining offshore wind capacity is used for hydrogen production.

Another important assumption is the simplification of the electricity and hydrogen transport routes by introduction of three central feed-in points at the coast. The choice of their locations is based on the configuration of the existing gas grid and the envisaged hydrogen backbone configuration (see Section 5). The proposed grid configuration does not consider existing electricity grid development plans and should not be interpreted as an optimal system configuration. The main purpose of central feed-in point(s) approach is to allow spatial analysis and determination of distances between offshore areas and onshore hydrogen pipeline backbone and costs of offshore grid and pipeline infrastructure. This simplification was necessary to reduce the number of sub-scenarios for a modelling task and does not imply realistic or technically and economically optimal configurations. The proposed high-level approximation should be interpreted in this context only.

Scenarios A1 and A2 for onshore hydrogen production – assumptions:

- All offshore wind farms are connected electrically to the onshore electricity grid.
- In the German case, the entire offshore wind capacity is aggregated to feed into one onshore gas network point (near Emden). For the Netherlands, the offshore wind capacity is aggregated to feed into the gas grid at two different feed-in points (Rotterdam and Groningen).

Scenarios B1 and B2 for offshore hydrogen production – assumptions:

- Offshore wind farms located further offshore – in zones 4 & 5 of the German EEZ and clusters 3, 4 & 5 in the Dutch EEZ – are not connected to the electricity grid and are directly feeding offshore electrolysers.
- In Scenario B2, for further offshore zones and clusters, additional electricity grid connections of 2 GW per zone or cluster are installed for technical reasons (for grid stability and support).
- Electricity produced at offshore wind farms located closer to the shore – in zones 1, 2 & 3 of the German EEZ and clusters 1, 2 & 6 in the Dutch EEZ – is fed into the electricity grid and is not used for hydrogen production.
- Hydrogen from individual electrolysers is transmitted to a collection point and then transported via a high-pressure pipeline to the defined feed-in points at the shore. The pipeline diameter varies between 250 and 1,100 mm (DN250; DN1100) as indicated in Appendix B2. The output pressure of the electrolysers is assumed to be 30 bar and is increased to 100 bar at the compressor station in order to provide sufficient pressure for transport via the pipeline [36].
- A central feed-in point is assumed for Germany (Emden) for determining the hydrogen production time series. For the Netherlands, the wind farms and electrolysers and the resulting quantities of hydrogen are divided between the two locations of Rotterdam and Groningen.
- The distances between the clusters and zones to feed-in points (Rotterdam, Groningen and Emden) are measured to assess which zones or clusters are connected to the electricity grid and which use offshore electrolysis (see Appendix B2).

Main features of the assumed hydrogen production scenarios are depicted in Figure 21, and an overview of the assumptions and methodology for each scenario is shown in Appendix B2.

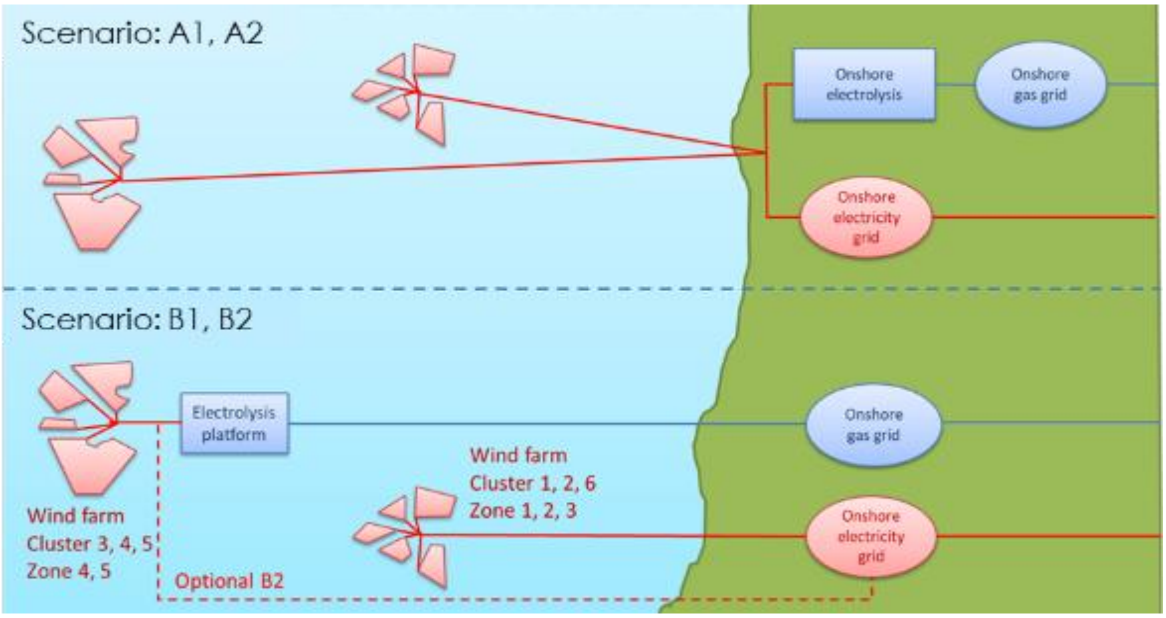

Figure 21: Infrastructure setting, wind farm clusters (NL) and zones (DE) in hydrogen production scenarios (own representation)

Maximum supply and minimum supply scenarios

Mixed concept for onshore and offshore electrolysis and a maximum supply scenario and sub-scenarios for hydrogen production are introduced by combining an A2 scenario restricted to a power supply only from offshore zones near to the shore wind and B1 scenario. The rationale is to provide a maximal potential hydrogen yield, which was then used in a supply and demand matching exercise within the analysis of the transport and storage infrastructure in Section 5. Scenario A1 is considered a minimum supply scenario due to the smallest hydrogen yield as a consequence of the low full load hours achieved in this scenario (see Appendix B2). In the following sections of this study, these scenarios are referred to as maximum supply and minimum supply scenario.

Deployment roadmap for electrolyser capacities

A deployment roadmap for the electrolysis capacity from 2025 to 2050 is developed based on the following assumptions:

- Initial ramp-up based on the national targets for offshore wind expansion and electrolysis capacity
- Final capacity available in 2050
- Linear deployment using a constant production volume for Germany and the Netherlands.

According to the German National Hydrogen Strategy, 5 GW of electrolysis capacity will be installed by 2030, with another 5 GW by 2035 [37]. It is assumed that 1.5 GW of electrolysers will be fed by offshore wind in 2030. This is the starting point of the electrolysis deployment related to offshore wind. According to the results of the offshore wind production assessment and the expected expansion of the electricity grid, additional electrolysis would only be required from 2035 onwards, but the expansion would then have to be massive. Since this is not plausible, a continuous electrolysis deployment of 1 GW per year from 2030 is assumed instead. The determined electrolyser capacities for each scenario are shown in the Table 4.

Table 4: Electrolysis deployment roadmap in Germany[9]

GW	Offshore wind assessment					
Year	**P inst**	**Pmax produced**	**Pmax produced in zone 1–3**	**Pmax produced in zone 4 & 5**	**Assumed grid capacity**	**Assumed electrolyser capacity**
2025	9.7	8.2	8.3	0.0	10.0	0.0
2030	19.4	16.5	16.5	0.0	15.0	1.5
2035	29.4	24.3	22.9	2.4	20.0	6.5
2040	37.9	32.1	23.7	9.7	22.0	11.5
2045	48.3	40.9	23.5	17.5	24.0	17.0
2050	53.4	45.2	23.5	21.8	24.0	21.5

According to the Dutch National Hydrogen Strategy, 0.5 GW of electrolysis capacity will be installed by 2025 and 3–4 GW by 2030. It is assumed that all electrolysers will be fed by offshore wind. This is the starting point of electrolyser deployment. An early start is necessary in order to achieve the maximum capacity by 2050. A constant electrolyser deployment of 1.5 GW per year is assumed between 2030 and 2050. The determined electrolyser capacities for each scenario are shown in the Table 5.

Table 5: Electrolysis deployment roadmap in the Netherlands

GW	Offshore wind assessment					
Year	**P inst**	**Pmax produced**	**Pmax produced in cluster 1,2,6**	**Pmax produced in cluster 3,4,5**	**Assumed grid capacity**	**Assumed electrolyser capacity**
2025	5.3	4.5	4.5	0.0	5.0	0.5
2030	11.6	9.9	9.9	0.0	10.0	3.5
2035	26.2	22.3	22.3	0.0	14.0	11.0
2040	40.3	34.2	26.0	8.2	18.0	18.5
2045	54.4	46.2	26.0	20.2	22.0	26.0
2050	67.9	57.7	26.0	31.8	26.0	31.7

[9] These assumptions go beyond current national targets, grid development planning and sectoral planning.

4.3.2. Hydrogen feed-in points and offshore wind area aggregation

Three hydrogen feed-in points along the German and Dutch North Sea coast are considered for connection to a hydrogen backbone pipeline. Groningen and the port of Rotterdam are considered for the Netherlands. For Germany, Emden is considered because a gas network expansion is planned, and a connection to the H_2 pipeline in the transport network is possible [38, 39]. Some of the areas in the German North Sea are closer to the Netherlands than to Germany. The connection of the German areas to Dutch locations was not considered because Groningen and Emden are so close to each other that the difference in distance is not significant for the cost analysis. Central points of connection to offshore wind areas were defined, which are used to determine the distance and the resulting costs of the hydrogen pipeline (subsea pipeline).

In Germany, a total of 24 areas were identified for offshore wind production. Figure 22 shows the aggregation of the German areas into 5 zones as used by the BSH [40]. In the Netherlands, there are a total of 53 areas for offshore wind production, aggregated into six clusters as shown in Figure 22**.** The clusters and zones were determined based on the proximity of the wind farms in order to reduce the calculation efforts and number of results to a reasonable limit. These clusters represent wind farms with comparable wind conditions, water depth and distance to the shore and are therefore used for the aggregated evaluation of electricity production and the determination of the electrolyser performance for the scenarios. The distances between the clusters and zones to the feed-in points (Rotterdam, Groningen, Emden) is determined to assess which zones or clusters are connected to the electricity grid and which use offshore electrolysis (see Appendix B2). These distances are needed to assess the cost of the subsea hydrogen pipeline. The costs of the electricity lines are determined using the distance directly to the shore.

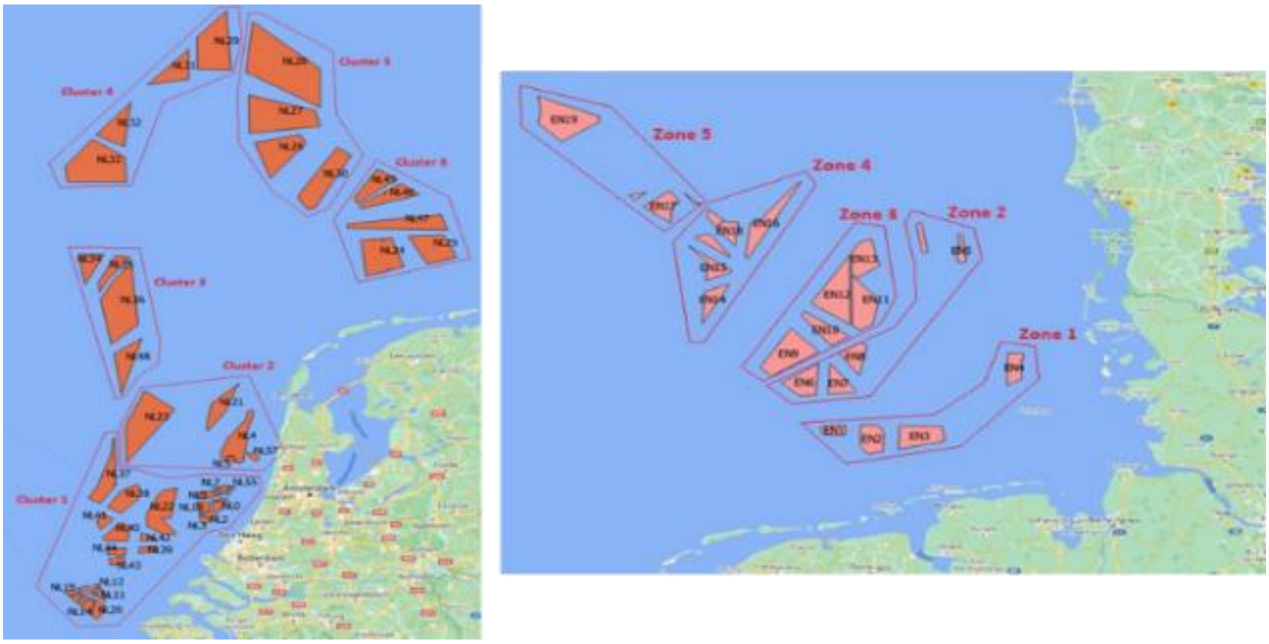

Figure 22: Wind areas aggregation into clusters (NL, left) and zones (DE, right) (own representation)

Hydrogen production time series and installed electrolyser capacities

Electrolysis capacity and full load hours for the electrolysis are determined on the basis of the offshore wind production time series and the electrolyser output. The offshore wind production time series of the different areas for every reference year are aggregated for the respective zones or clusters. The maximum offshore wind power production of the respective zone or cluster available for electrolysis was set to an average of 85 percent[10] of installed offshore wind capacity. This maximum offshore power output is used instead of the total installed capacity for determining the size of the electrolysis and the hydrogen production time series (see the section entitled Deployment roadmap for electrolyser capacities).

All areas in the German and Dutch North Sea were aggregated into a hydrogen production profile for every reference year for the evaluation of the onshore scenarios A1 and A2. For the evaluation of the offshore hydrogen scenarios B1 and B2, the offshore wind production time series of the different areas on the German and Dutch North Sea are aggregated into several production time series for every reference year, according to the five zones for Germany and the six clusters for the Netherlands, respectively.

The resulting capacity of installed electrolysers is shown in Figure 23 and in Appendix B2. Additionally, modelled electrolysis capacity for the SEN-1 area[11] is 247 MW producing 24,107 metric tons H_2/a, which is added to the production of hydrogen in zones 4 and 5 in the scenarios B1 and B2 for all reference years. SEN-1 is the first area for other forms of energy generation, envisaged in the German EEZ (see Section 6.5.1), that could accommodate a first pilot project for the offshore hydrogen production in Germany.

[10] Based on the calculated time series for each scenario/cluster the value of the maximum occurring power of the aggregated wind farms averages typically at 85% of the installed wind power

[11] SEN-1 has an area of 28.8 km², which is approximately 30% of the area of zone EN8.

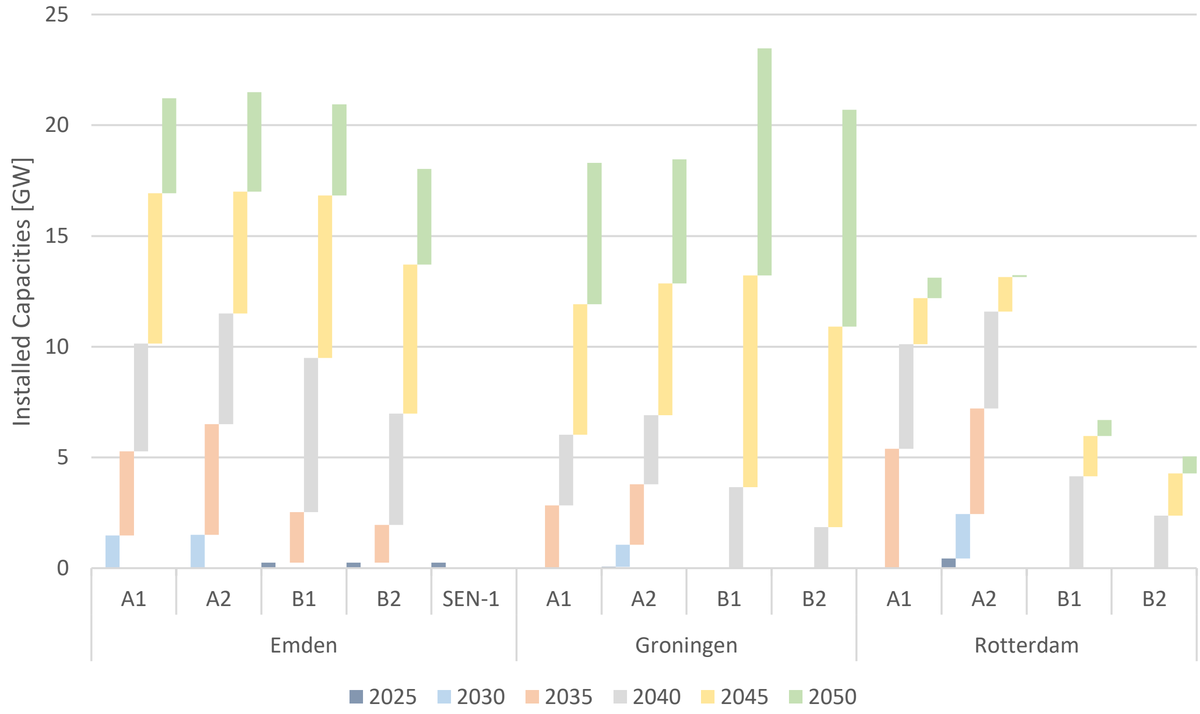

Figure 23: Installed electrolysis capacity for the different scenarios and reference years at Emden, Groningen and Rotterdam

In accordance with the electrolysis deployment roadmap, first minor electrolysis capacities will be realised by 2030, with the exception of the SEN-1 area already existing from 2025 onwards. Initially, these capacities will be located onshore in immediate proximity to the feed-in points. First offshore electrolysis capacities in Germany are assumed in the model as early as 2035, while in the Netherlands, they are not modelled until 2040. The reason for the assumption of constrained offshore electrolysis capacities is attributed to the development of the zones and clusters further offshore at a later stage in this conservative scenario.

Figure 23 shows that the peaks of installed capacitates are to be expected in 2050. While installed capacities of over 20,000 MW are reached for the Emden (scenarios A1, A2 and B1) and Groningen (scenarios B1, B2) feed-in points, the maximum installed capacities for the Rotterdam feed-in point vary between 10,000–15,000 MW for scenario A1 and A2. The relatively low offshore electrolysis capacity for the Rotterdam feed-in point is due to the fact that only cluster 3 is considered for supply chain concepts B. Furthermore, the aggregated Rotterdam offshore wind areas in the clusters are smaller in size and have a decreasing offshore wind energy density towards the English Channel.

Based on the duration curves for each scenario and reference year (available in Appendix B2), hydrogen production time series for all scenarios for Germany and the Netherlands and all reference years are calculated. Through aggregating these, the annual hydrogen production quantities for all scenarios for Germany and the Netherlands can be determined as shown in Figure 24 (for an alternative depiction, see also Appendix B2). The duration curves are also used to determine an overview of the full load hours (see Appendix B2).

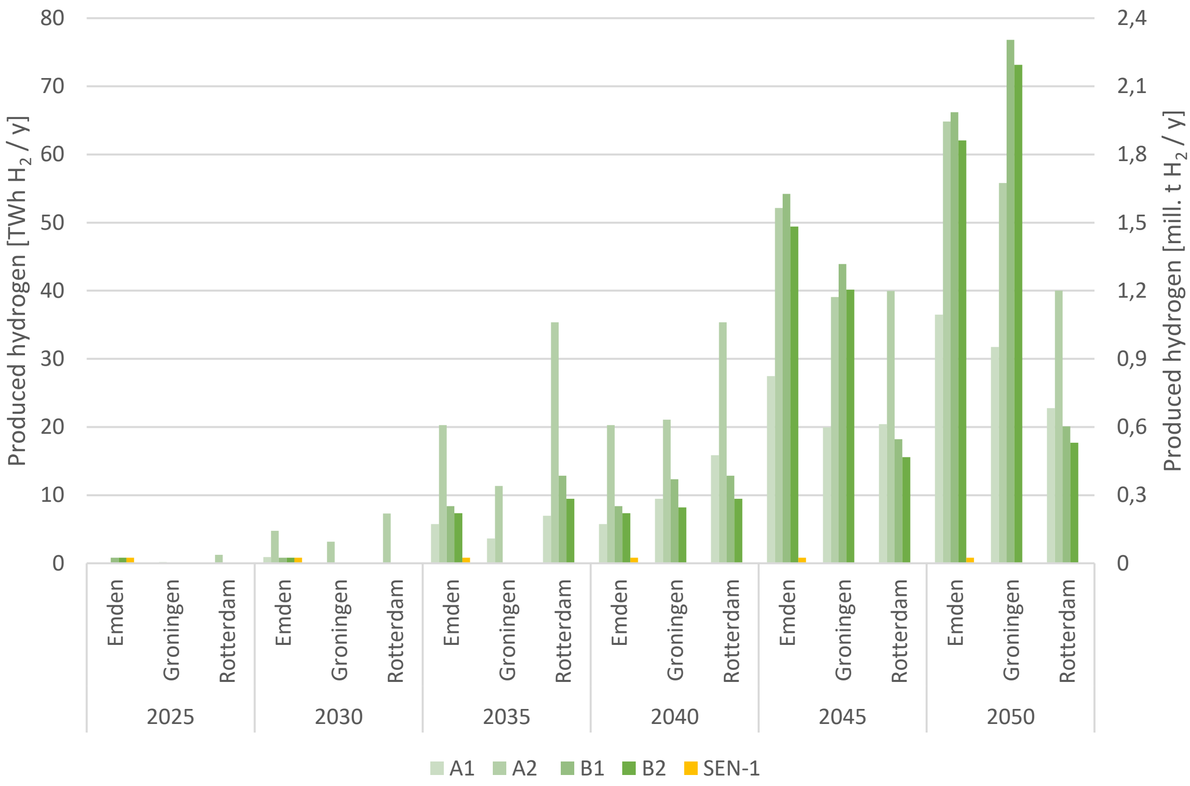

Figure 24: Hydrogen production quantities in metric tons per year for the different scenarios and reference years at Emden, Groningen and Rotterdam

In view of the installed electrolysis capacity and the load duration curves, a concurrent development of the annual hydrogen quantities can be observed. The model shows that large-scale deployment of onshore hydrogen production is foreseen as early as 2030 (especially in scenario A2), while substantial quantities of hydrogen produced offshore (supply chain concept B) are expected from 2035.[12]

For all three feed-in points, Figure 24 shows that scenario A2 will have the highest output of hydrogen by the reference year 2040, ensuring a potential hydrogen market ramp-up. Once the more distant zones and clusters have been developed and realised, similar quantities of hydrogen of up to 1.5 metric tons can be produced according to scenario B1 (and partially in B2) in Emden, and Groningen in the reference year 2045. A maximum amount of hydrogen can be produced for all feed-in points and scenarios after the full expansion of the areas in 2050. The

[12] Note that currently several pilot and demonstration projects (both on and offshore production) are already in operation or under preparation in both Netherlands and Germany.

smaller hydrogen quantities produced at the Rotterdam feed-in point can be attributed to the smaller installed electrolysis capacities in cluster 1, 2 and 3.

Figure 25 compares the minimum and maximum possible hydrogen quantities as the sum of all three feed-in points (DE: Emden + NL: Groningen, Rotterdam) from the minimum supply scenario (A1) and maximum supply scenario (A2 near-B1). The first significant quantities of approx. 0.5 million metric tons of hydrogen in scenario A1 (surplus energy use) can be produced in the reference year 2035. An almost equal amount of hydrogen can already be ensured from 2030 in the scenario for maximum hydrogen yield (maximum supply scenario). If the German and Dutch offshore zone and clusters were to be fully developed by 2050, this would result in 2.7 million metric tons of hydrogen in the minimum supply scenario and in 7.1 million metric tons of hydrogen in the maximum supply scenario. Furthermore, a comparison of the offshore wind and electrolysis expansion shows a more constant rate of expansion for the maximum supply scenario. Here, the expansion rate varies from 18 to 27%, while in the minimum supply scenario it is 17–31%. Finally, in the analysed scenarios, electricity shares from offshore wind for hydrogen production vary between scenarios and reach higher values from 2035, when 10–50% of electricity from offshore wind is converted to hydrogen. A detailed overview of electricity shares for hydrogen production is available in Appendix B2.

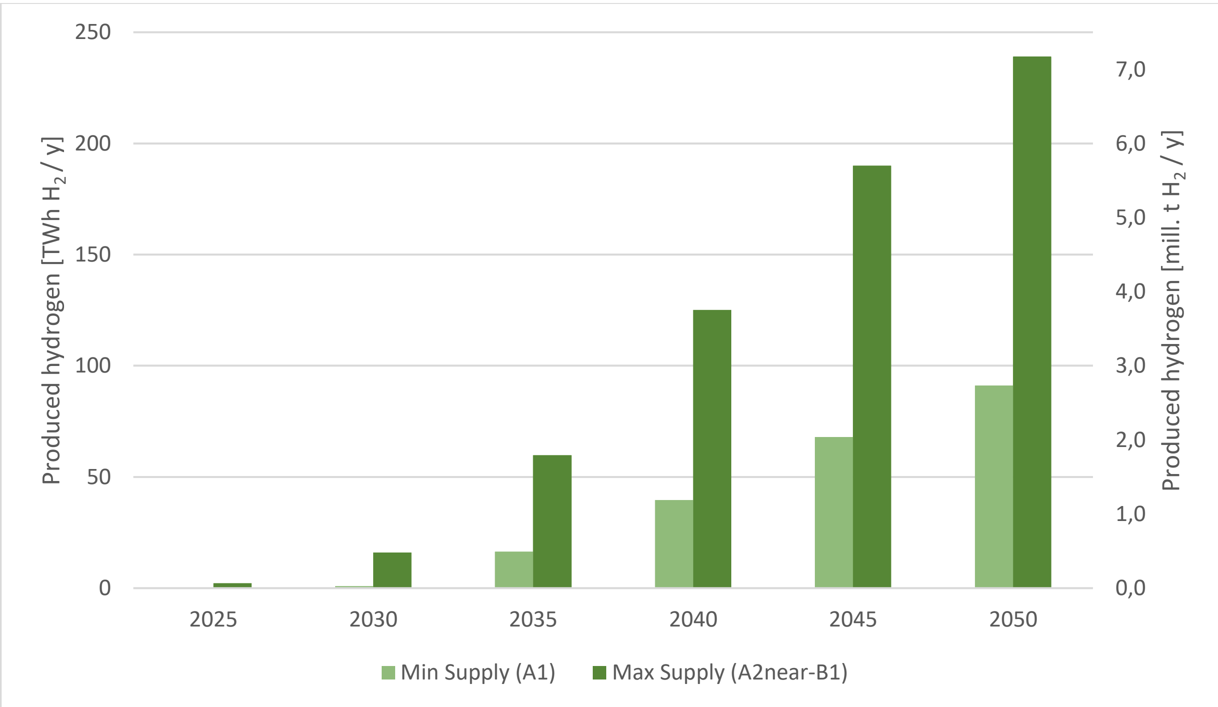

Figure 25: Hydrogen production quantities as the total of all three feed-in points from the minimum supply scenario (A1) and maximum supply scenario (A2 near-B1)

4.3.3. Hydrogen production cost assessment

This section assesses the levelised cost of hydrogen (LCOH). In addition to the levelised cost of electricity (LCOE; see Appendix B1 – LCOE Models), which were calculated based on the results in Section 4.2, this section presents a more detailed view on the other cost components of the LCOH calculation. The calculation of CAPEX and OPEX for offshore wind turbines is based on Härtel et al. (2018) and can be viewed in detail in Appendix B2.

For the onshore electrolysis, CAPEX cost curves are developed taking into account the installed capacity and the year of installation. A PEM electrolysis is assumed as the technology of choice, and a cost curve model is used[13] (see Appendix B2). In order to account for the specific requirements of operating electrolysers offshore, additional technical aspects and costs for the offshore hydrogen production ("marinisation") are included. For the hydrogen pipeline, the cost model developed is applied [36]. Details can be found in Appendix B2. The costs of repurposing existing offshore gas pipelines are expected to be significantly lower than the construction of new hydrogen pipelines. The cost of hydrogen production is calculated using specific cost per kg of hydrogen.

The levelised cost of hydrogen (LCOH) method allocates the entire hydrogen production costs, taking into account component replacement, interest rates, and residual values at the end of the economic lifespan. It is based on the annuity method with constant annual cost throughout the lifetime considered (Verein deutscher Ingenieure VDI 2012a, 2012b). The financing cost parameters for LCOE and LCOH are identical. The observation period (project time span) is 25 years, the interest rate amounts to 5%, and the cost escalation rate is 1.455%, which is the average inflation rate of Germany over the last 20 years [41].

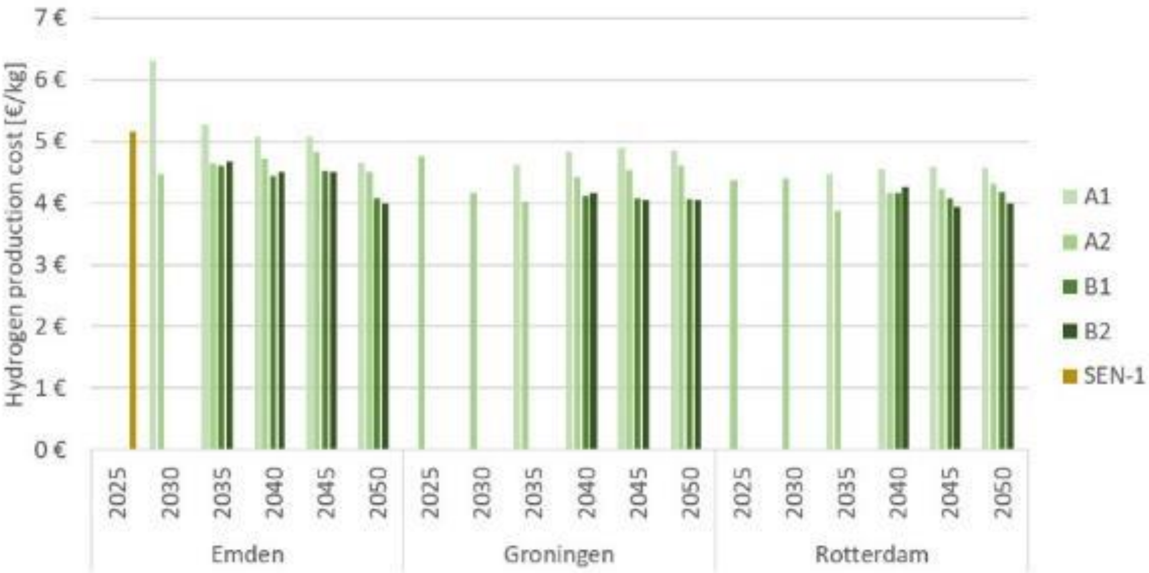

Figure 26: Hydrogen production cost for the different supply chain concepts and reference years at Emden, Groningen and Rotterdam.

Based on this methodology, hydrogen production costs for all sub-scenarios, reference years, and feed-in points in Germany and the Netherlands are determined, as shown in Figure 26. Additionally, the value range for the calculated cost of electricity from offshore wind – denominated as a wind farm LCOE – is depicted in Figure 27. The levelised costs of hydrogen (LCOH) vary between 6.30 EUR/kg for sub-scenario DE A1 Emden, and 3.88 EUR/kg for sub-scenario NL A2 Rotterdam. In addition, Appendix B2 provides a detailed overview of each individual value.

[13] Taking into account data from International Energy Agency (IEA) 2019, Smolinka et al. 2018, Bertuccioli et al. 2014, van 't Noordende und Ripson 2020, Bazzanella und Ausfelder 2017

Figure 26 shows that for all feed-in points and reference years, scenario A1 (surplus energy use) has the highest levelised cost of hydrogen. The only major deviation (with 6.30 EUR per kg H_2) can also be traced back to the minimum supply scenario. This is due to the fact that hardly any grid bottlenecks occur in the initial phase of offshore wind expansion, leading to a low electrolysis utilisation of only 890 full load hours. With an increasing utilisation of the electrolysers (higher full-load hours), the LCOH for all feed-in points in scenario A1 fall to below 5.00 EUR/kg in 2050, but still do not reach the cost of scenario A2 (fixed percentage of electricity).

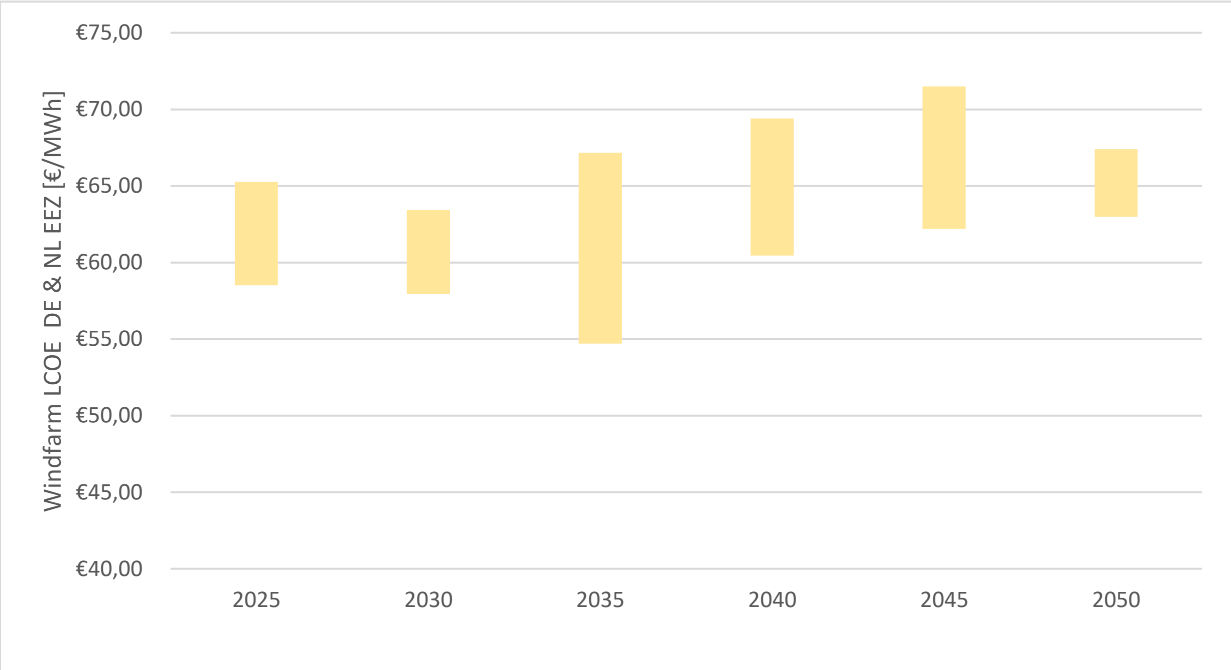

Figure 27: Ranges of the calculated cost of electricity (LCOE) from offshore wind applied in determination of the levelised cost of hydrogen (LCOH)

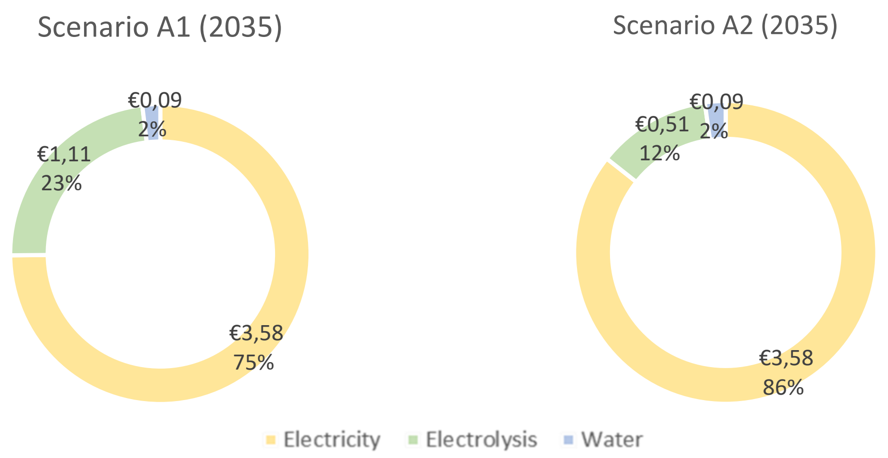

Figure 28: Allocation of LCOH for scenario A1 and A2 in the reference year 2035

The breakdown of LCOH into various cost components shows that the electrolysis costs excluding electricity consumption contribute 23% to total LCOH in scenario A1 compared to 12% in scenario A2. The main difference can be explained due to the significantly lower full load hours of the electrolysers, even with equal LCOE (see Figure 28). In absolute terms, the costs in A1 (1.11 EUR/kg) related to the hydrogen production are more than twice as high as in scenario A2 (0.51 EUR/kg). In principle, the same applies to the reference year 2050 (see Figure 29): a higher number of full load hours leads to better utilisation rates and tend to lower the specific costs of electrolysis per kg of hydrogen.

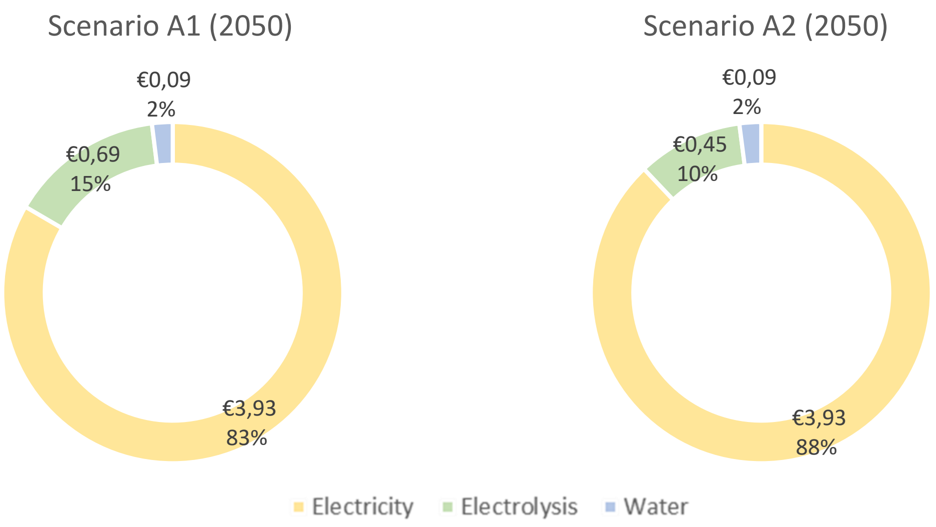

Figure 29: Allocation of LCOH for scenario A1 and A2 in the reference year 2050

The gradual expansion and development of the more distant offshore zones and clusters in the German and Dutch EEZ lead to relatively lower cost for supply chain concept B over time (Emden and Groningen from 2040; Rotterdam from 2045 onwards) when compared with supply chain concept A.

The reasons for this are the different proportions of levelised costs of electricity (LCOE). In particular, the lower costs can be attributed to the difference between electricity and hydrogen transport costs and to increased full load hours of supply concept B (see Figure 30).

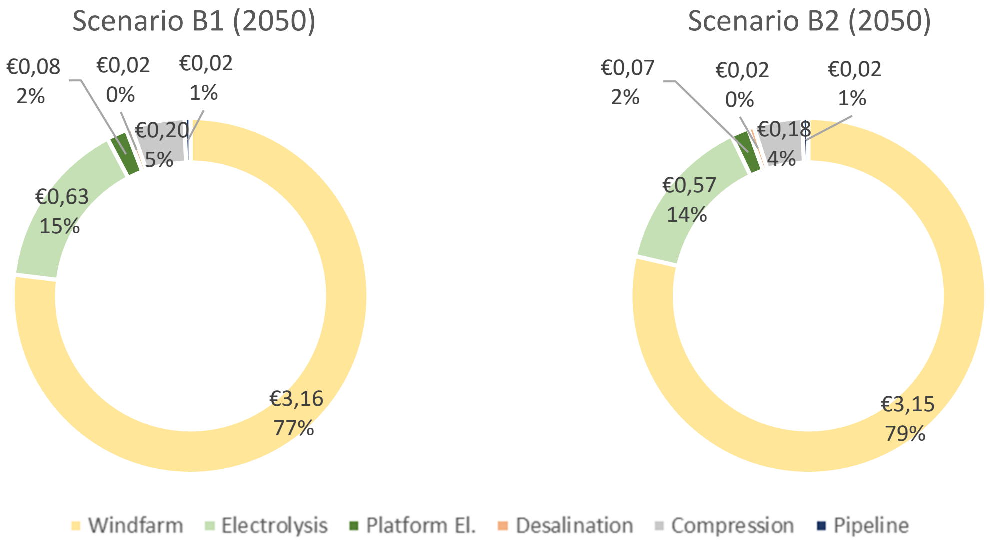

Figure 30: Allocation of LCOH for scenario B1 and B2 in the reference year 2050

4.4. Decarbonisation potential

4.4.1. System boundaries and CO_2 footprints

The decarbonisation potential of green hydrogen is one of the important drivers of the future utilisation of this energy carrier. An assessment of the decarbonisation potential is carried out following the results of modelling of green hydrogen production from offshore wind on the North Sea. For this purpose, the production process of green hydrogen from offshore wind, together with alternative hydrogen production processes and natural gas, is assigned the respective CO_2 footprints. As alternative production processes, grey hydrogen[14] and blue hydrogen[15] are considered. The CO_2 footprint is defined as the production-related emissions assigned to the production of 1 MJ of gaseous hydrogen or natural gas (methane). As the reference for comparison to business as usual, a fossil fuel comparator is considered. The comparator is defined by the EU Commission for emission calculations of biofuels and is appropriate here, because it served as a benchmark for the priority energy infrastructure category of electrolysers in the EU Regulation [49]. The analysis of the CO_2 footprint does not take into account the direct use of electricity with a naturally lower CO_2 footprint, as the produced hydrogen in this study is assigned to decarbonise the hard-to-abate sectors and applications in transport, refinery and PtL production as well as in the chemical industry.

Differences in total production-related emissions for the hydrogen quantities between the reference production process and the fossil fuel comparator represent the decarbonisation potential. In order to assess CO_2 footprints, the Life Cycle Analysis (LCA) methodology is applied. Various sources are considered in defining comparable system boundaries for the LCA [42, 43, 44]. Figure **31** shows the system boundaries that are taken into account when it comes to the hydrogen production LCA. The system boundaries for the LCA include the emissions related to the respective energy source, meaning to the electricity production from offshore wind and the production of the natural gas (upstream emissions of natural gas exploitation and transport included), as well as emissions related to

[14] Produced via steam methane reforming (SMR) or auto thermal reforming (ATR).

[15] Produced via SMR/ATR with carbon capture and storage (CCS).

the respective process of hydrogen production, together with the emission related to hydrogen compression necessary for transport via pipeline. In the case of blue hydrogen, emissions related to the handling of the captured CO_2 (CCS) are also considered.

For green hydrogen production from offshore wind, a CO_2 footprint ("Green H_2") is set according to the value proposed in the North Sea Energy study, as the analysed use case fits well with the use cases in this study [109]. For grey and blue hydrogen, emissions related to the natural gas production, defined as upstream emissions[16], play a crucial role in the evaluation of the CO_2 footprint. Assumptions on the level of upstream emissions of natural gas are not unified[17] in the literature, which leads to large discrepancies in assessing emissions related to blue hydrogen. For the current study, the CO_2 footprint for grey and blue hydrogen production is based on Timmerberg (2020) for the SMR process [46]. The values are representative for blue hydrogen from natural gas imported to Europe, with a methane leakage rate of 1.7%. The considered energy carriers and respective CO_2 footprints are shown in

[16] Upstream emissions include emissions from extraction, processing and transport of natural gas until the point of production of hydrogen.

[17] Upstream emissions of methane are strongly influenced by the "methane loss rate" during transport. The methane loss rate depends on different factors like distance between source and consumption locations, and the way it is transported (pipeline or LNG). [45]

Table 6. A detailed overview of assumptions and sources is available in Appendix B3.

System boundaries for Life Cycle Analysis – hydrogen production related emissions

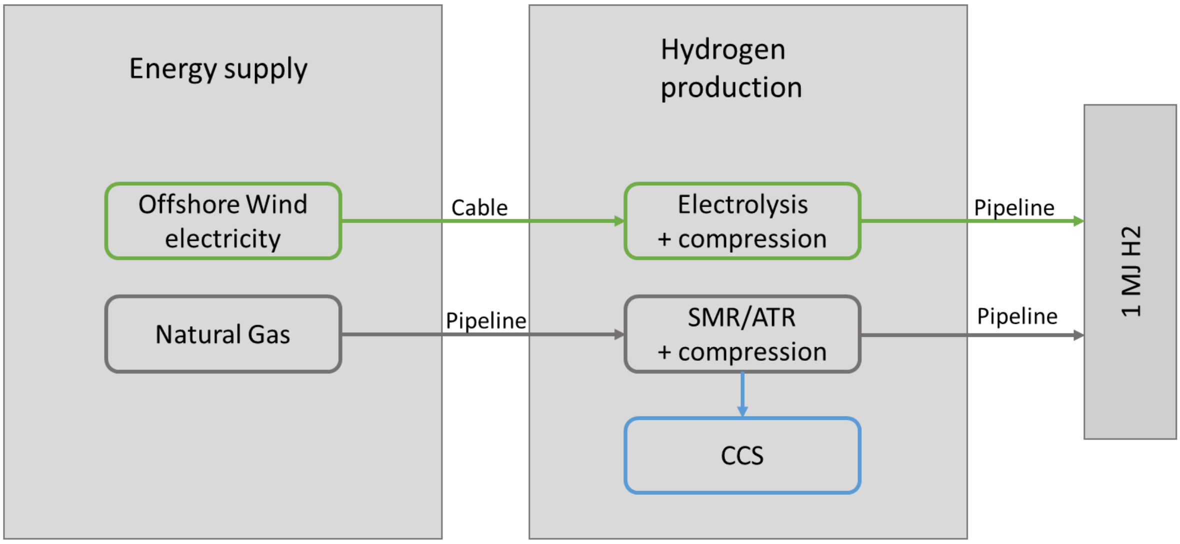

Figure 31: System boundaries for the LCA of green, blue and grey hydrogen production (own representation)

Table 6: CO_2 footprints of fossil fuel comparator, methane and the analysed hydrogen production processes [46, 47, 48]

Reference fuels / energy carriers	CO_2 footprint
Fossil fuel comparator (EU)	0.0940 kg CO_2/MJ
Natural gas (methane)	0.0730 kg CO_2/MJ
Blue H_2 (import gas)	0.0458 kg CO_2/MJ (5.49 kg CO_2/kg H_2)
Blue H_2 (domestic gas)	0.0185 kg CO_2/MJ (2.22 kg CO_2/kg H_2)
Green H_2 (offshore wind, North Sea)	0.01 kg CO_2/MJ (1.2 kg CO_2/kg H_2)

4.4.2. The decarbonisation potential of hydrogen deployment

The quantities from those scenarios with a minimal and a maximal hydrogen yield (see Section 3.2) and their corresponding CO_2 footprints are used to determine the total production-related emissions for the modelled hydrogen production. Then, the decarbonisation potential is determined as CO_2 emissions savings by taking into account cumulative annual differences of total emissions between all considered reference fuels and energy carriers. The emissions derived for the same energy consumption taking into account the fossil fuel comparator for the transport sector of Directive (EU) 2018/2001 of 94 g CO_2eq/MJ are also considered [49]. The resulting cumulative savings of CO_2 are shown in Figure 32 and Figure 33. Between 272 and 810 million metric tons of CO_2 emissions would be mitigated by deployment of green hydrogen from offshore wind as a replacement for fossil fuels from 2025 to 2050. CO_2 mitigation in the case of blue hydrogen deployment varies substantially, depending on the source of natural gas. Thus, blue hydrogen can mitigate between 43 and 90% of CO_2 emissions compared to green hydrogen.

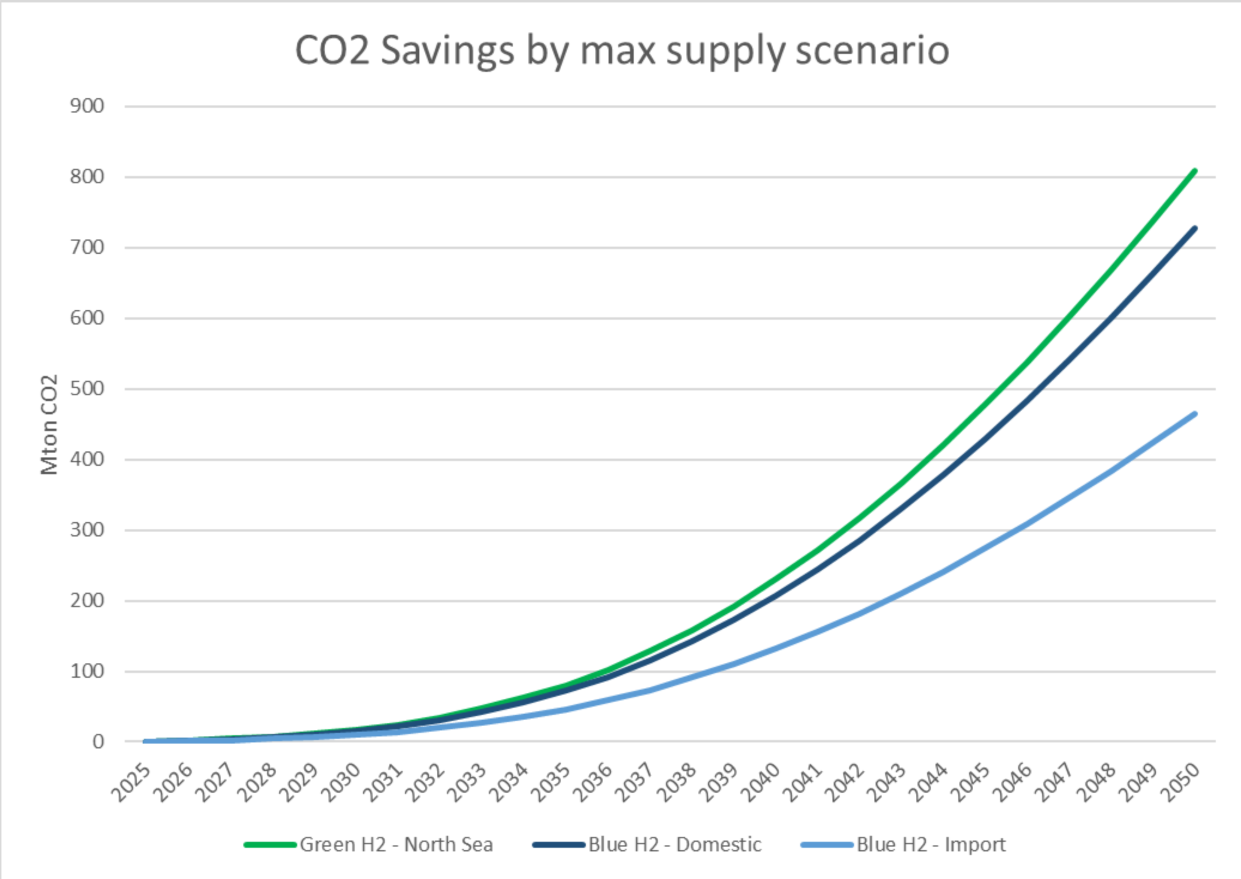

Figure 32: Cumulative CO_2 emissions savings by deploying green hydrogen, blue hydrogen or methane as a replacement of fossil fuels in the maximum supply scenarios (own representation).

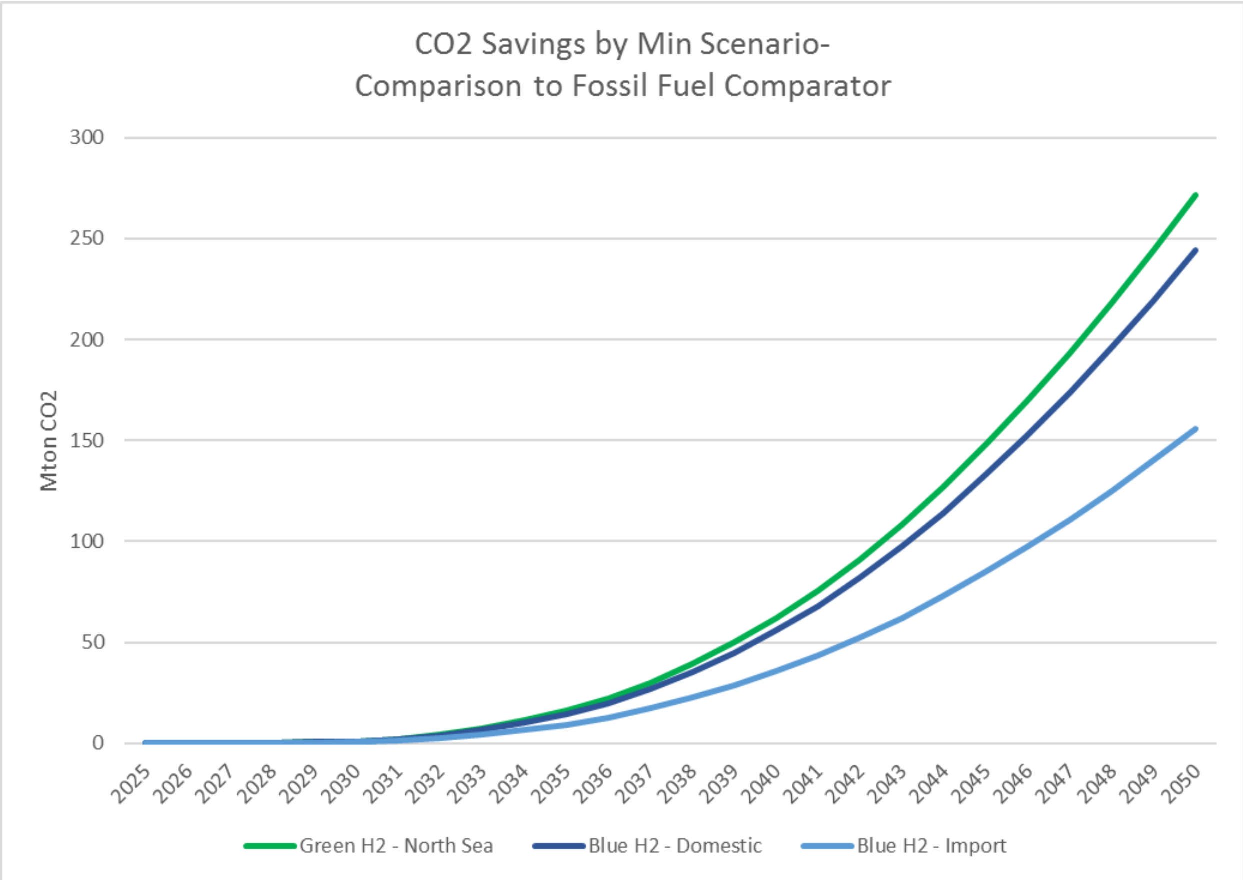

Figure 33: Cumulative CO_2 emissions savings by deploying green hydrogen, blue hydrogen or methane as a replacement of fossil fuels in the minimum supply scenarios (own representation).

5. Hydrogen transport, storage and import

5.1. Introduction

This section examines the hydrogen transport and storage infrastructure. This infrastructure connects hydrogen demand in the selected industry clusters in the Netherlands and North Rhine-Westphalia to the production of hydrogen from offshore wind along the North Sea coast. To balance variability in offshore wind production and the resulting hydrogen production, the balancing potential of using large-scale subsurface hydrogen storage in the Netherlands and the north-western part of Germany is examined. In case of a mismatch between annual supply and demand, the role of importing hydrogen from overseas is assessed. Regarding the geographical scope of the study, import locations are limited to the western part of the Netherlands (the port of Rotterdam) and the north-western part of Germany (e.g. the port of Wilhelmshaven as a potential candidate for the import cluster).

Probable infrastructure scenarios are outlined for combinations of supply and demand scenarios. Envisioned hydrogen networks are supplemented by calculations using a solver that minimises the total distance that the hydrogen molecules must travel between the supply, storage and demand sites. Given the known gas grid capacities we estimate the utilisation of an envisioned hydrogen network, identify bottlenecks for transport and storage and explore actions to resolve constraints. Drawing on the overall analysis, we recommend actions to realise the hydrogen network outlined in the scenarios over the next decade. We further qualitatively describe some potential infrastructure modifications needed to successfully implement combinations of scenarios for demand, supply, storage and import.

5.2. Methods – hydrogen transport, storage & import infrastructure

5.2.1. Transport infrastructure network

Hydrogen transport infrastructure would consist of the transmission network of pipelines with compressor stations spread across the network. In a letter published in April 2020, the Government of the Netherlands communicated its strategy on hydrogen along with a corresponding policy agenda [50]. The Dutch strategy states that the hydrogen transport infrastructure will likely develop as a network sector, as is the case with natural gas. In June 2021, the HyWay 27 study was concluded anticipating a hydrogen backbone across the Netherlands and €750 million has been reserved for its development by the Dutch Government.[18] Correspondingly, the Federal Ministry of Economic Affairs and Energy in Germany also published its National Hydrogen Strategy in June 2020 [37]. The German strategy expects that parts of the existing natural gas network will be usable for hydrogen. Furthermore, additional networks are envisioned exclusively for transporting hydrogen. Reliance on the existing natural gas transmission network for future hydrogen transport is an underlying assumption in both the German and Dutch hydrogen strategies.

[18] https://www.rijksoverheid.nl/onderwerpen/prinsjesdag/miljoenennota-en-andere-officiele-stukken

The natural gas distribution network in the Netherlands is owned and operated by Gasunie N.V., whereas in Germany, there are 16 transmission system operators represented by the Association of Transmission System Operators Gas e.V. (Vereinigung der Fernleitungsnetzbetreiber Gas e. V., abbreviated as FNB Gas) [51].

Both the Dutch and German TSOs have published their visions of a national hydrogen backbone. To analyse the transnational hydrogen infrastructure, we have taken the hydrogen backbone visions of the respective national TSOs as the starting point. For the Netherlands, Gasunie's hydrogen backbone is used, and for Germany, FNB's H2-Netz Vision is used [52] [53].

The backbone enables current and future demand centres (industrial hubs including chemical, steel industries and refineries) to be connected with supply location (electrolyser sites, overseas import) and storage sites (e.g. subsurface gas storages in salt caverns and porous reservoirs). See Figure 34 for the envisioned hydrogen network in the Netherlands and Germany.

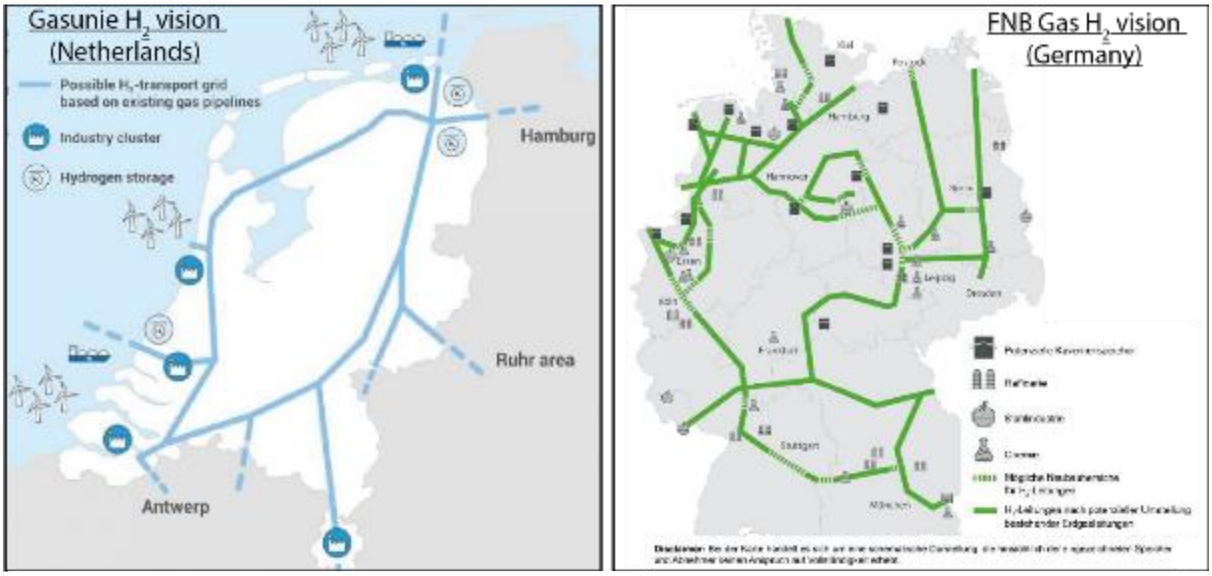

Figure 34: Envisioned hydrogen networks in the Netherlands (source: Gasunie) and Germany (source: FNB Gas)

As the proposed hydrogen network is largely based on existing natural gas pipeline corridors and infrastructure, we adopted natural gas network specifications such as pipeline length, diameter, number of lines and topology. Note that in this phase of the study, other modes of transporting hydrogen, for example, by truck, train and inland shipping are excluded. For the Netherlands, network topology in GIS-format was publicly available from the public-private research program North Sea Energy [54]. However, for Germany there was no public database containing detailed network topology in GIS-format that could be used. Therefore, this study relies on the network topology extracted in an earlier project at FZ Jülich based on the natural gas network published in ENTSO-G and publicly known network specifications [110]. An envisioned network topology consisting of demand, supply, import, and storage nodes is constructed by combining the information in a GIS database. In Figure 35, the envisioned network is projected on a map to show possible connections between production, supply, storage, and import clusters (or nodes). This map is then translated into a network model that simplifies the arrangement of the main elements of the network (network topology). This yields simplified network topologies shown in Figure 36. Network simplification was in line with the supply, demand and publicly available German grid's spatial resolution. The default network (*Network = default*) reflects an envisioned hydrogen backbone in the Netherlands and Germany. The variant of this network (*Network = WithRotterdamDEpipe*) includes a pipe segment from Europoort (Rotterdam, Netherlands) to Wesel (Germany) via Venlo (Netherlands), in addition to the default network. This pipeline segment is of interest when transporting hydrogen directly from the port of Rotterdam to the southern part of the Netherlands and western part of NRW, and it has been considered in the hydrogen vision of the port of Rotterdam, for example [56]. Both network topologies include the entire envisioned hydrogen backbone for the Netherlands, and the envisioned hydrogen backbone in the NRW region for Germany. The rest of the envisioned German hydrogen backbone (outside NRW) was excluded from the model as those regions were out of scope, and consequently no demand/supply regional data was available for those regions.

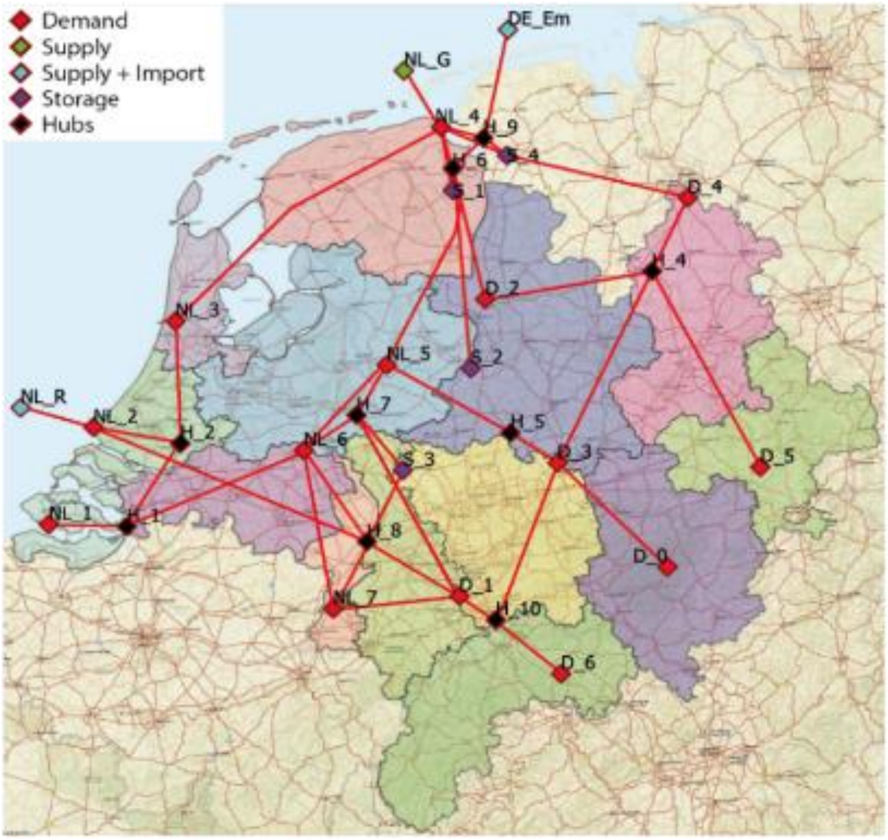

Figure 35: Envisioned hydrogen network for the Netherlands and North Rhine-Westphalia showing the demand, supply, import, storage and hub nodes modelled in transport analysis

For each pipe segment in the network, the corresponding pipe diameter and number of lines (i.e. parallel pipelines) were converted to an equivalent hydrogen flow by assuming 50 bar operating pressure and a temperature of 10°C with 20 m/s flow velocity. Note that both the operating pressure range and flow velocity are under detailed study by TSOs and are subject to change in the future[19]. Project HyWay 27 estimates pipeline capacities of 10 to 15 GW for a 36-inch pipeline depending on the pressures. See the appendix for a comparison of capacities estimated via approach considered in this report and HyWay 27. Figure 36 shows the maximum flow capacity for the corresponding pipe capacity. The pipe capacity calculated includes the total capacity of all parallel lines. In Appendix C2, a similar network plot with the number of parallel lines is included for reference.

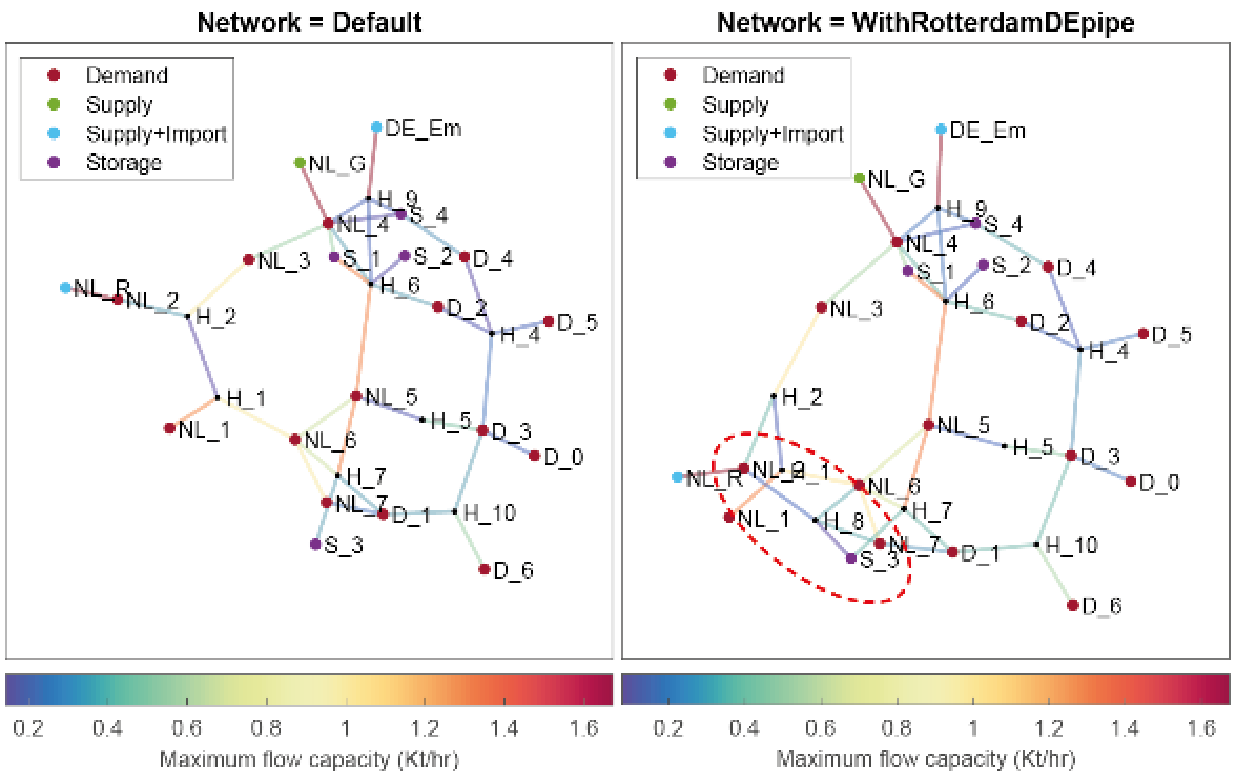

Figure 36: Simplified network topologies showing the maximum flow capacity per pipeline segment

It is also assumed that the hydrogen pipelines can be used in both directions. This is needed for some parts of the backbone because significant amounts of hydrogen flow to the storage sites during periods of high oversupply (high production and import), and in periods of shortage, these stored volumes are made available again using the network in reverse direction.

5.2.2. Storage infrastructure

The intermittent supply and demand profiles during the year create hourly fluctuating deficits and excesses. In order to balance the flow in the hydrogen grid during hourly fluctuations, hydrogen storage in salt caverns is in-

[19] Additional information was received from FNB Gas & Gasunie (HyWay 27 project team) during the course of this project expecting hydrogen flow velocities as high as 50 m/s. The consequence of this technical variation is elaborated upon in Appendix C1.

cluded in the study. Appendix C1 describes the formulae used to estimate the required volume of storage capacity. These storage volumes reflect capacity needed to balance a copper-plated rendition of the grid. Dynamic operating conditions, strategic reserves, security of supply targets, export buffers, etc. would likely require additional storage capacity. These additional capacities magnitude and role of porous reservoirs to fulfil the need has not been investigated in the current study.

Selected storage sites and potential

Geotechnically suitable salt structures that could contain salt cavern(s) for gas storage are documented by NLOG and by LBEG for the Netherlands and Germany, respectively [58] [59]. An assessment of the suitability of these salt caverns and structures can be found in Juez-Larré et al. (2019) [57].

In the current study, salt structures with existing caverns are selected. While the caverns in these salt structures are currently used for storing natural gas, they could be re-used for storing hydrogen in the future. Additionally, new caverns could be developed within the same structures. Sites that have a geographical advantage resulting from their existing connection to the gas transmission grid, or due to their location along the border of the Netherlands and North Rhine-Westphalia, are identified and preferentially included. On this basis, the following preliminary list of salt cavern storage sites are identified and included in the analysis: Zuidwending (NL), Epe (DE), Xanten (DE) and Jemgum (DE). However, there are other salt caverns in the north-west of Germany that could also be used for hydrogen storage, such as Nüttermoor and Etzel. The chosen storage sites provide a broad spatial reach of the caverns with respect to the modelled grid. Since each site equally shares the injection and production needs from the grid, the chosen storage sites can be a proxy for other sites not explicitly included. For instance, from a modelling perspective, Jemgum could also represent Nüttermoor and Etzel. Figure 37 shows the salt cavern storage sites included in the transport analysis along with other potential salt cavern sites in the Lower Saxony area of Germany.

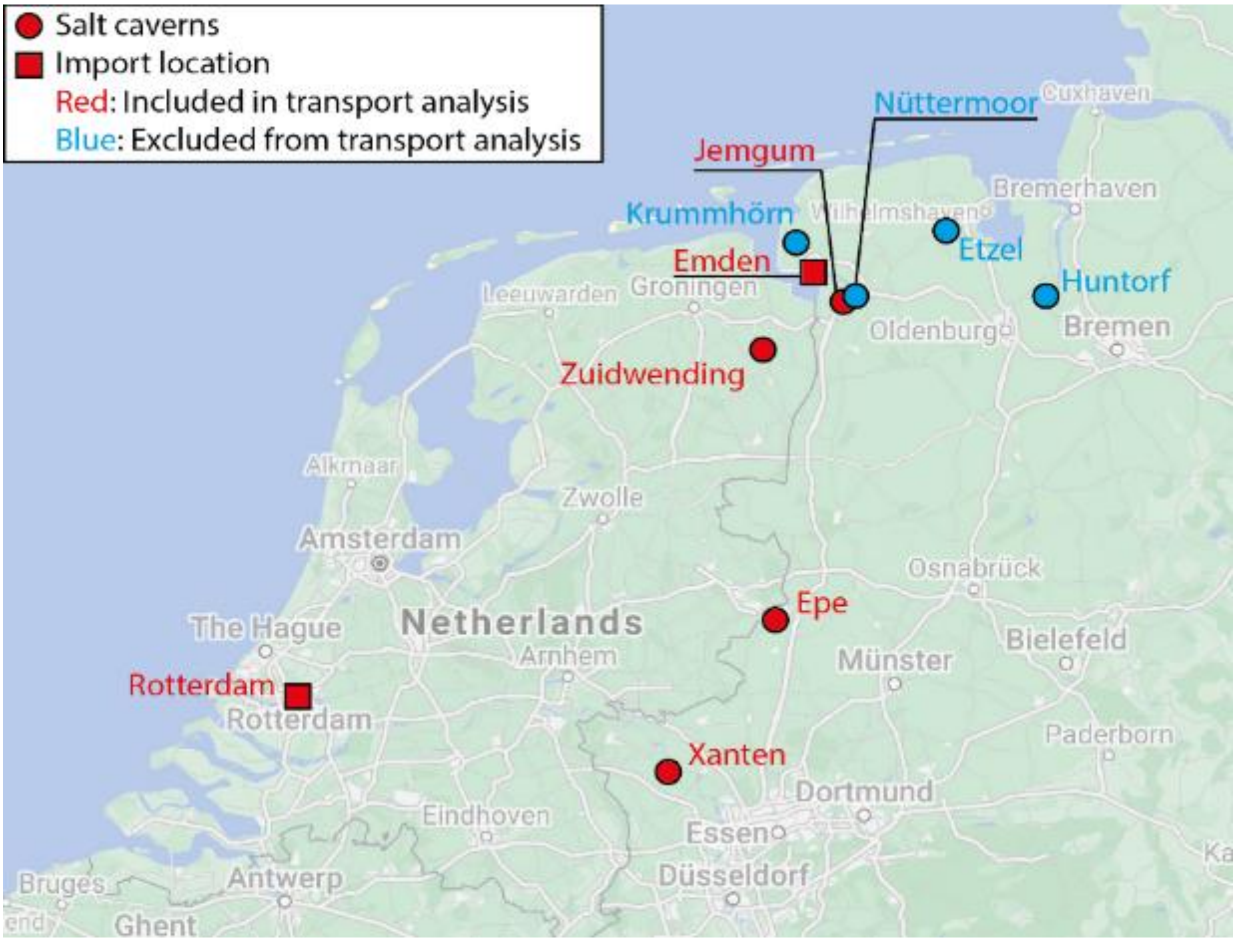

Figure 37: Salt cavern sites for potential storage and import. Transport analysis model includes the Zuidwending (S_1), Epe (S_2), Xanten (S_3) and Jemgum (S_4) salt caverns

There are several underground salt structures along the border region of the Netherlands and Germany near Groningen (NL) and Lower Saxony (DE). Few studies have attempted to estimate the total onshore salt cavern storage potential. Caglayan et al. estimate that the Netherlands and Germany have a total onshore cavern storage potential of ca. 400 TWh and ca. 10 PWh hydrogen, respectively [30]. However, in another study that focused on the potential in the Netherlands ca. 43 TWh of hydrogen in over 300 salt caverns was estimated as a theoretical potential [57]. In practice this theoretical potential is not feasible and it is expected that a maximum of 60 salt caverns could be developed in NL[20] by 2050. The large difference in the estimated theoretical potentials is due to differing geometric cavern volumes, operating pressures and cavern spatial placements assumed by these two studies. This highlights that the estimated hydrogen storage potential is very sensitive to such parameters. Additionally, physical and safety issues could also arise due to the proximity of salt structures to populated regions. All these aspects limit the practical salt cavern storage potential.

[20] TNO 2021, Ondergrondse Energieopslag in Nederland 2030–2050, TNO2021 R11125

The Zuidwending storage site in the Netherlands has concrete plans to develop one cavern for hydrogen storage while possibility adding three more caverns for this purpose [61]. There is also a potential to add 10–20 more caverns given a total capacity of 3.5–6.0 TWh of hydrogen [60]. A detailed geological assessment for the Jemgum, Epe and Xanten sites in Germany is not published to the best of our knowledge. In this study we assume that these four sites have the potential to provide the storage capacities estimated in the next section. These four sites are located close to the existing gas transport grid. Salt cavern costs and time frames are shown in Section 6. Further site specific scrutiny and geological assessment is needed to verify the required storage capacity estimates of this study. Based on discussions with industry stakeholders we foresee that existing salt caverns used to store natural gas could be re-purposed to store hydrogen within a time frame of 1–1.5 years for technical aspects. Non-technical aspects such as permits, social acceptance, etc. could take additional time. Some experts in this field project two to three years for repurposing salt caverns as this has not been done before. Creating new caverns at existing storage sites will take about two to three years for technical aspects. However, this does not account for additional time needed for hydrogen storage permits and other non-technical aspects such as social acceptance. This additional time frame could take one to three years for the first few projects. Furthermore, the business case for hydrogen storage in caverns is also being investigated. All these issues highlight the urgency in taking action such that sufficient hydrogen storage capacity can be available by 2030.

Storage site constraints
The maximum injection and production capacity of a salt cavern is limited by two factors. The first limitation is due to well size. For a typical well production tubing of 9 5/8 inches, a production of up to 136 metric tons/hr of hydrogen (= 4.5 GW) is theoretically feasible at a 80 bar difference between the cavern and wellhead, with a maximum flow velocity of 100 m/s to not exceed the erosion threshold velocity [111]. The second limitation is imposed by the regulatory guidelines limiting the maximum pressure change over a 24 hour period to a set value. In the Netherlands, the allowed pressure gradient over 24 hours is 10 bar [111]. Since the cavern pressure changes due to injection and/or production of hydrogen, this poses a limitation to the maximum injection and/or production rate over a span of 24 hours. Considering the caverns located at the Zuidwending site in the Netherlands, with an average geometric volume of ca. 0.75 Mm^3 (Energystock, 2017), a 10 bar pressure change translates to a sustained maximum flow rate (injection or production) of 20 metric tons/hr of hydrogen (= 0.65 GW) for the caverns. Based on the maximum production and injection rate analysis for the Zuidwending site, this results in a limit of 20 metric tons/hr of hydrogen flow sustained over a 24 hour period.

5.2.3. Import infrastructure

One of many options to supplement hydrogen supply is to import hydrogen at the port of Rotterdam (Netherlands) and the port of Wilhelmshaven[21]. In the current study, import from overseas is the assumed option to supplement hydrogen supply. By diversifying potential import locations, the overall grid utilisation can be distributed more evenly across the grid. Multiple import locations across different geographies could also aid in balancing grid flow variations during temporary supply and/or demand surges. According to the port of Rotterdam's vision, the grid could support a combined self-production and import an annual throughput of 20 million metric tons of hydrogen

[21] Note that this import node is assumed in the simplified network similar to the supply node denoted by DE_Em in Figure 36.

(666 TWh hydrogen equivalent, LHV) in 2050 (Rotterdam, 2020). The port of Wilhelmshaven has not published its hydrogen vision at the time of writing, but it remains an important port as it is the only German deep-water port. It currently has an LNG capacity output of 10 bcm (= 97.7 TWh considering 35.2 MJ/m^3 gross calorific value) of natural gas per year [62].

The hydrogen import supply chain consists of four basic elements: a hydrogen conversion plant, an export terminal, shipping, and a reconversion terminal. The supply chain could be expanded as shown in Figure **38** depending on the mode of transport and the choice of energy carrier. Of the available energy carriers, liquid hydrogen transport, liquid organic hydrogen carriers and ammonia would be suitable for green hydrogen energy transport in terms of technology [112]. An additional supply of hydrogen will be needed in order to meet projected demand when supply is insufficient. In this study, it is assumed that any hydrogen deficit would have to be met by importing hydrogen from overseas through the port of Rotterdam in the Netherlands. Consequently, the option of importing hydrogen at the port of Wilhelmshaven in Germany is also included in the analysis. Since the port of Wilhelmshaven is geographically close to Emden, Emden is considered as the import node in our network topology. This allows for performing a sensitivity analysis on the import location and its impact on the hydrogen grid. In transport scenarios, where import from both the port of Rotterdam and the port of Wilhelmshaven is considered, the total an-

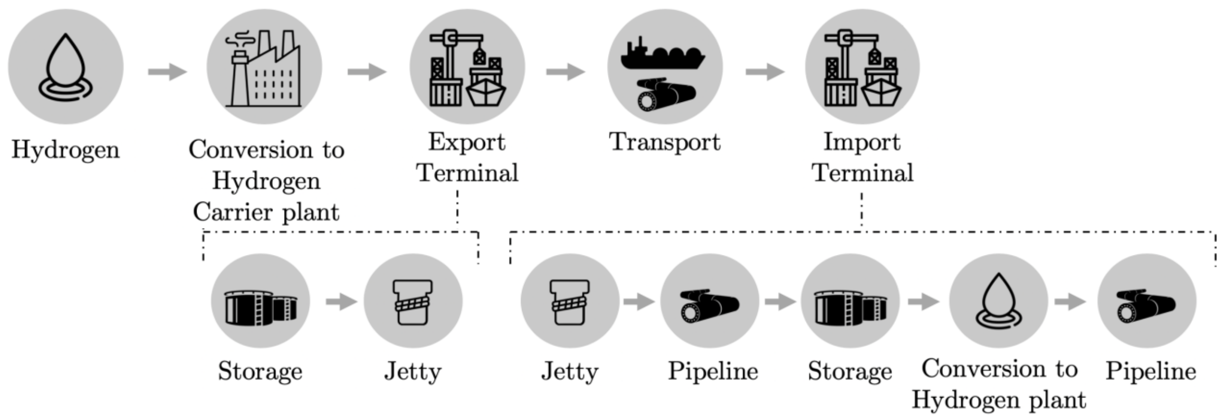

Figure 38: Hydrogen import supply chain elements overview (Lanphen, 2019)

nual import was divided equally over both the import locations. Subsequently, the hourly import is calculated by assuming that the annual import is divided uniformly over the full year, i.e. a flat import rate over the year is considered for simplicity. By this definition of the annual import, net hydrogen demand and supply (with import) over a given year is zero. Appendix C3 describes the formulae used to estimate import rates.

5.2.4. Hydrogen transport infrastructure modifications

Infrastructure elements

The future hydrogen transport infrastructure is anticipated to largely consist of converted existing natural gas infrastructure. This network consists of several parallel pipelines in the Netherlands transporting high and low calorific gas. The recently announced HyWay 27 project considers reusing one of the pipelines to create a pure hydrogen transport backbone ring in the Netherlands by 2027. Other pipelines are foreseen to become available after 2030. Other H_2 carriers such as LOHC, ammonia and MeOH are not investigated in the current study. For instance, the infrastructure consists of several elements such as the pipeline, pipe fittings, valves, compressor stations and metering and control stations. All these elements must be screened for compatibility with hydrogen with clear guidelines on how to address them. To this end, engineering guidelines for gas network TSOs & DSOs are developed in the HYREADY project.

Re-purposing natural gas pipelines for hydrogen transport requires careful assessment of integrity loss due to hydrogen embrittlement. Hydrogen embrittlement is a process by which diverse steels grades could become brittle and fracture due to exposure to hydrogen [63].

Other elements of infrastructure such as fittings, flanges and seals also need to be inspected for sufficient tightness to hydrogen. Pipe fittings that are leak-free for natural gas are not necessarily leak-free for hydrogen as hydrogen is a smaller molecule than most molecules in natural gas. Where needed, these elements need to be tightened or replaced to be compatible with hydrogen. Compressors would likely need to be replaced to be compatible with hydrogen [64]. Compatibility of metering and monitoring elements in control stations with hydrogen is currently investigated [113].

While there are many technical questions that still need to be addressed for the entire natural gas network's compatibility with hydrogen, Gasunie has modified an existing natural gas transport pipeline for use with hydrogen-rich natural gas (ca. 80% hydrogen, 20% methane) in the province of Zeeland (NL) [114]. The 12-km long, 16-inch pipeline transports hydrogen produced as a by-product at Dow chemical to Yara for consumption. The pipeline has been operational since November 2018 [115]. Although used for transporting a hydrogen-rich gas mixture, this pipeline has been verified for use with 100% hydrogen [114]. In order to address technical questions for successfully modifying nation-wide natural gas infrastructure to transport hydrogen, there are many ongoing projects by joint public and private consortiums focussing on the various aspects listed above [116].

Before existing natural gas infrastructure can be used for transporting hydrogen, the operational safety and maintenance procedures also need to be further developed, in addition to the technical challenges (Krom, 2020). The French network operators investigated technology-related and economic conditions for injecting hydrogen into natural gas networks [117]. They recommend integrating 10% hydrogen in the network by 2030 and afterwards increase to 20% in a sequential manner, parallel to upgrading the network to be compatible with 100% hydrogen.

5.3. Transport analysis via network model

The transport analysis uses an energy system network model that balances flow through the network. The network is described by a series of nodes and connections. Here, the nodes represent the industrial demand clusters, supply and import locations, and underground hydrogen storage sites. The connections represent the pipelines that connect various nodes with each other as described in Section 5.2.1.

The flow through the network is optimised by minimising the sum of the "flow-distance" parameters. Flow-distance is the product of flow and pipeline length. Minimising the sum of the flow-distance parameters makes it possible to identify the shortest flow path through the network. The model thus minimises the total distance that the hydrogen molecules must travel between the supply, import, storage, and demand sites for every hour of a given year. The minimisation model is additionally constrained by the corresponding supply, import, storage and demand values. This means that the network model should find a solution to absorb all produced and imported hydrogen and meet the hourly demand in all individual demand clusters.

Import and storage rates are divided equally across all import and storage nodes. While the storage sites are fixed to four in this study, the number of import locations varies according to the specific transport scenario. The detailed energy system network model is described in Appendix C3.

Various transport scenarios are investigated to study the effect of demand and supply scenarios on the network topologies. The analysis is thus structured broadly to start with a baseline case upon which the sensitivity of certain network features is studied. In this manner, a probable network operating strategy can be envisioned and potential bottlenecks in the network can be identified.

5.3.1. Selected scenarios

The transport analysis calculations are based on the demand and supply scenarios described in Sections 3 and 4. The baseline demand scenario is chosen and the minimum and maximum supply scenarios are chosen. The baseline demand scenario is based on the projected hydrogen demand for the Netherlands and Germany. The maximum supply scenario gives an upper limit, whereas the minimum supply scenario gives a lower limit of green hydrogen production from offshore wind. Several scenarios for the transport analysis are envisioned by combining the base demand and two supply scenarios for the years 2030 to 2050. For example, a transport scenario consisting of a combined base demand with maximum or minimum supply would cover potentially extreme import/storage and grid flow magnitudes over the years.

The baseline case transport scenario combines the default network topology (see Section 5.2.1) with hydrogen import at the port of Rotterdam from overseas. A sensitivity analysis studies the additional import capacity from overseas at the port of Wilhelmshaven. In scenarios where certain parts of the network have bottlenecks, it is assumed that the network capacity can be expanded by adding additional lines. Finally, in select scenarios, the Rotterdam to Ruhr pipeline (Europoort to Wesel via Venlo) is included in the network topology to decongest the grid.

5.4. Results

5.4.1. Demand, supply, storage and import estimates

By comparing the annual demand and supply estimates over the years (2030 to 2050), the study shows that hydrogen demand is higher than hydrogen supply. Demand growth over the years is exponential, whereas supply only shows linear growth. Figure 39 shows that annual hydrogen demand is higher than supply by 6–21 TWh in 2030 and by 162–310 TWh in 2050. This results in a need for an additional source of hydrogen to meet demand. In this study, we consider importing hydrogen as additional source of hydrogen.

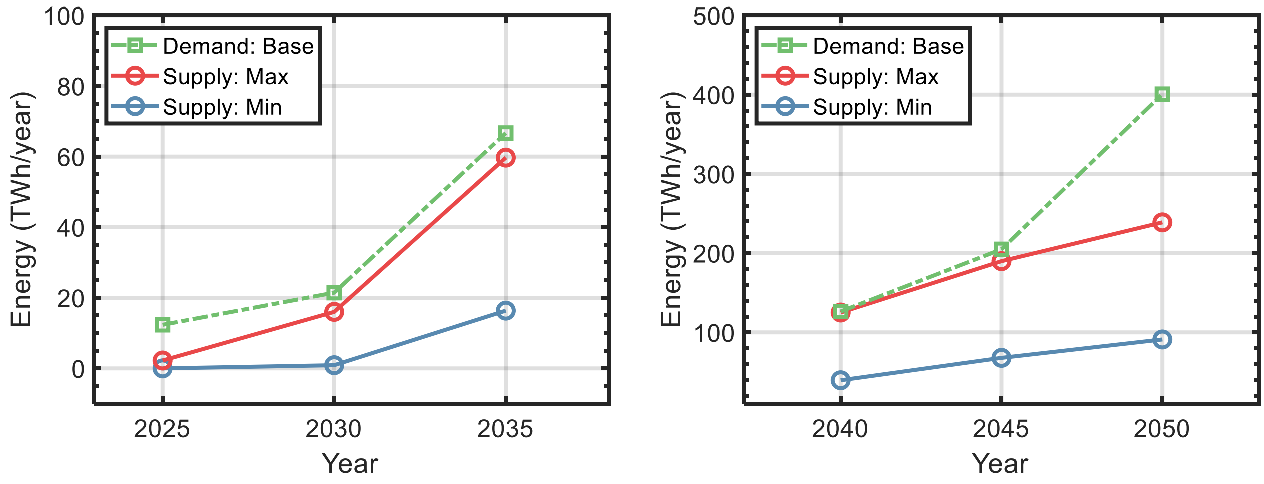

Figure 39: Annual hydrogen demand, minimum and maximum supply from [left] 2025 to 2035 and [right] 2040 to 2050

Figure 40 shows the annual storage and import capacity from 2025 to 2050 for two transport scenarios consisting of combinations of the demand and minimum and maximum supply scenarios. The storage capacity needed to balance annual demand and supply fluctuations (including import) increase from 0.2–1.5 TWh in 2030 to 12–14 TWh in 2050. For all years, demand is greater than supply. In Appendix C4, an example plot of the storage site injection and production (without and with import) is shown.

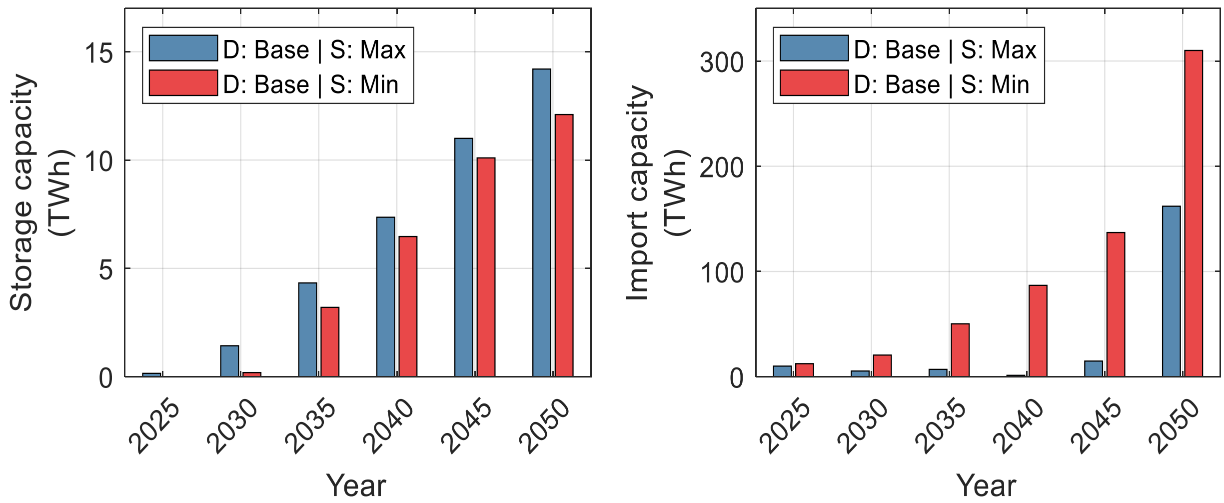

Figure 40: Annual storage and import capacity from 2025 to 2050 for two transport scenarios consisting of a combination of the baseline demand and the minimum and maximum supply scenario

A typical salt cavern with a geometric volume of 1 Mm^3, operating at a working pressure of 75–190 bar and located at a depth of 1050m has capacity of ca. 250 GWh of hydrogen energy (lower heating value) [118]. Assuming 250 GWh as the single cavern storage capacity results in the need for one to five caverns in 2030. This number grows to 49–57 caverns by 2050 (see Figure 41). Note that this estimate is based on a flat import rate throughout the year and an equal split of storage needs across the NL + NRW regions. The consideration of a dynamic import profile along with an optimal use of storage capacity can be used to optimise the number of caverns. With the estimates of the number of caverns that can potentially be made available (existing and potentially new ones) this means that sufficient storage capacity is available at all times based on the assumptions in this study. However, site-specific storage potential assessments should be undertaken to verify the storage potential at the suggested locations. The estimated storage capacity needed is subject to the various assumptions considered in the supply and demand assessment such as flat import profile, weather profile for 2012, copper-plated transport rates, etc. Aspects such as effect of extreme weather year and variable import rate are not included in the analysis. Additional discussion on assumptions can be found in Appendix C.

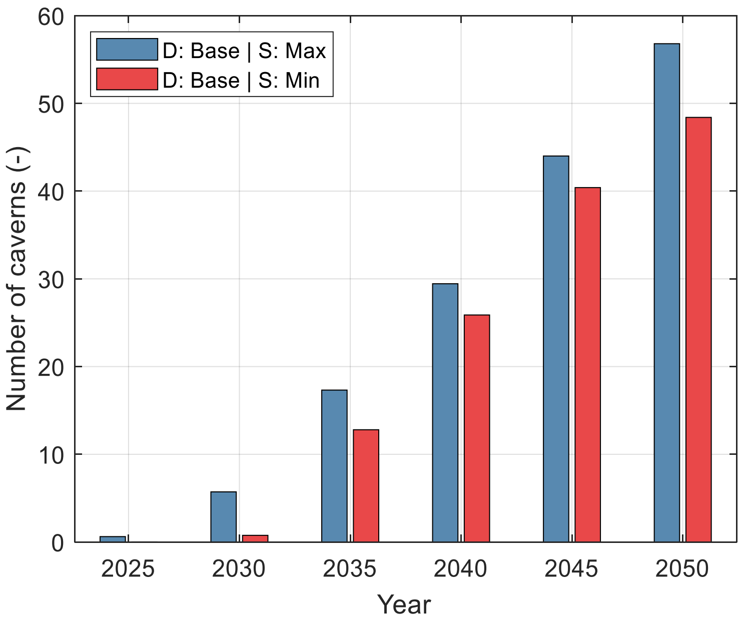

Figure 41: Number of caverns for baseline demand and minimum and maximum supply scenario assuming a single cavern capacity of 250 GWh

For the storage rates estimated for the transport scenarios, we calculate the maximum feed-in and production rate in a year that the sites would collectively need to match supply and demand. The instantaneous hourly feed-in and production rates are integrated to estimate daily (over 24 hours) feed-in and produced amounts. The daily amounts are then assumed to be fed in or produced from the storage site uniformly over 24 hours. The maximum feed-in and production rate refers to the maximum over a given year. For 2030, the maximum feed-in rate is 50 metric tons/hr (demand, maximum supply), whereas the maximum production rate is estimated to be 47 metric tons/hr (demand, maximum supply). For 2050, the maximum feed-in rate is 802 metric tons/hr (demand, maximum supply), whereas the maximum production rate is estimated to be 755 metric tons/hr (demand, maximum supply). For all examined years, the number of caverns shown in Figure 41 would suffice to meet restrictions imposed by maximum feed-in and production rates. Consequently, there is no negative impact on the estimated instantaneous cavern feed-in and production rates in the transport analysis due to the regulatory limit of 10 bar on pressure change over 24 hours. Figures for maximum feed-in and production rates of the transport scenarios in 2030 and 2050 are shown in Appendix C3.

5.4.2. Transport scenarios

In the following sections we discuss the results from the transport analysis with the energy system network model up to the year 2050.

Year 2030

The envisioned grid has sufficient capacity for both supply-demand scenarios in 2030: demand with minimum and maximum supply. The figure below shows the mean flow through the network along with the normalised mean flow through the network for the maximum supply scenario with import at the port of Rotterdam. The mean is calculated over one year by calculating the hourly flow through the network linked to the hourly demand and supply projections. The flow data at each pipe segment is available for analysis. Figure 42 [left] shows the maximum and minimum normalised flow for each pipe segment over the whole year. This is an indicator of grid utilisation. As the normalised flow values are close to 0, it shows that a relatively small portion of the total grid capacity is used. In Appendix C4, a detailed annual flow profile in a pipe segment is shown as an example for the level of detail available in the transport analysis model.

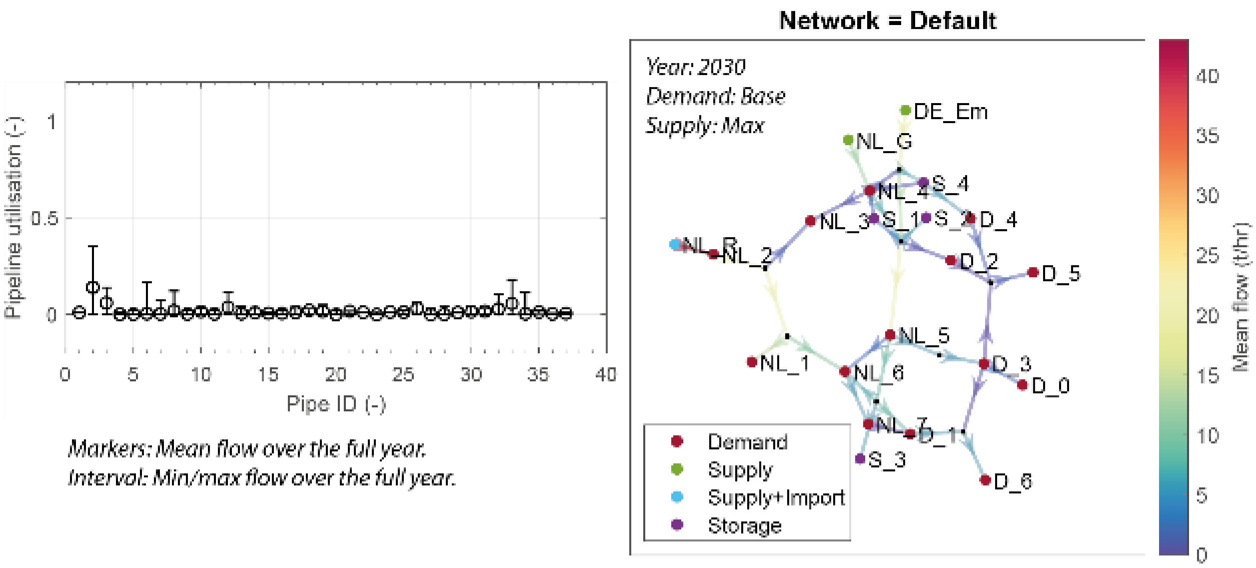

Figure 42: [left] Circles show the normalised mean flow for each pipe segment in the network. Values close to 0 indicate a small portion of the total grid capacity is used. [right] Network diagram showing the mean flow for 2030, baseline demand and minimum and maximum supply scenario with import from overseas at the port of Rotterdam.

While the default scenario assumes that the entire gas network is available for pure hydrogen transport, it is considered more realistic that hydrogen demand will gradually increase while reducing the natural gas usage [119, 120]. A dual network (or combined grid) with part for hydrogen and part for legacy natural gas users would likely co-exist during transition to pure hydrogen. To simulate a 2030 scenario consisting of a dual network, we reduce the number of parallel lines in the default network topology to contain a single line. Figure 61 shows the corresponding results. The results show that a single line network also has sufficient capacity to transport the projected hydrogen flows. Note that the actual change in normalised flow rate is too small for most pipe segments to visually stand out compared to Figure 42. However, small changes can be observed, such as the utilisation (normalised flow rate) of pipe segment with ID 3 (from NL_2 to H_2) increases when a single line is considered. In a nutshell, the grid capacity is sufficient in2030 to meet hydrogen transport requirements based on the estimates of demand, supply import and storage.

Year 2035

Compared to 2030, annual demand and supply more than double in 2035. The increased supply and demand cause the overall flow through the network to increase significantly. This higher flow in 2035 is not likely to be supported by a single line network (detailed results in Appendix C4).

We further analyse the flow through the grid by assuming the entire grid is available for hydrogen. When import from overseas occurs at the port of Rotterdam, the local pipe segments near Rotterdam operate at maximum capacity. These simulations are shown in the left column in Figure 43. The network diagram highlights the pipe segment that operates at maximum capacity, whereas the red data in the normalised flow plot indicate the mean flow in that pipe segment. One of the ways to reduce the local pipe utilisation is to spread supply and import locations to other relatively underutilised locations in the grid. For instance, local pipe utilisation at Rotterdam could be reduced by spreading import of hydrogen between the port of Rotterdam and the port of Wilhelmshaven. These simulations are shown in the right column of Figure 43. Spreading import location between Rotterdam and Wilhelmshaven allows for operating the local pipe segments near Rotterdam below maximum capacity, freeing up capacity for possible contingencies.

These results should be placed in the context of the assumption that storage capacity is split equally across the four sites considered. Hence, more mitigation options to alleviate grid congestion are possible and need to be investigated more carefully, especially given the high uncertainties in projected demand and infrastructure assumptions used in this study.

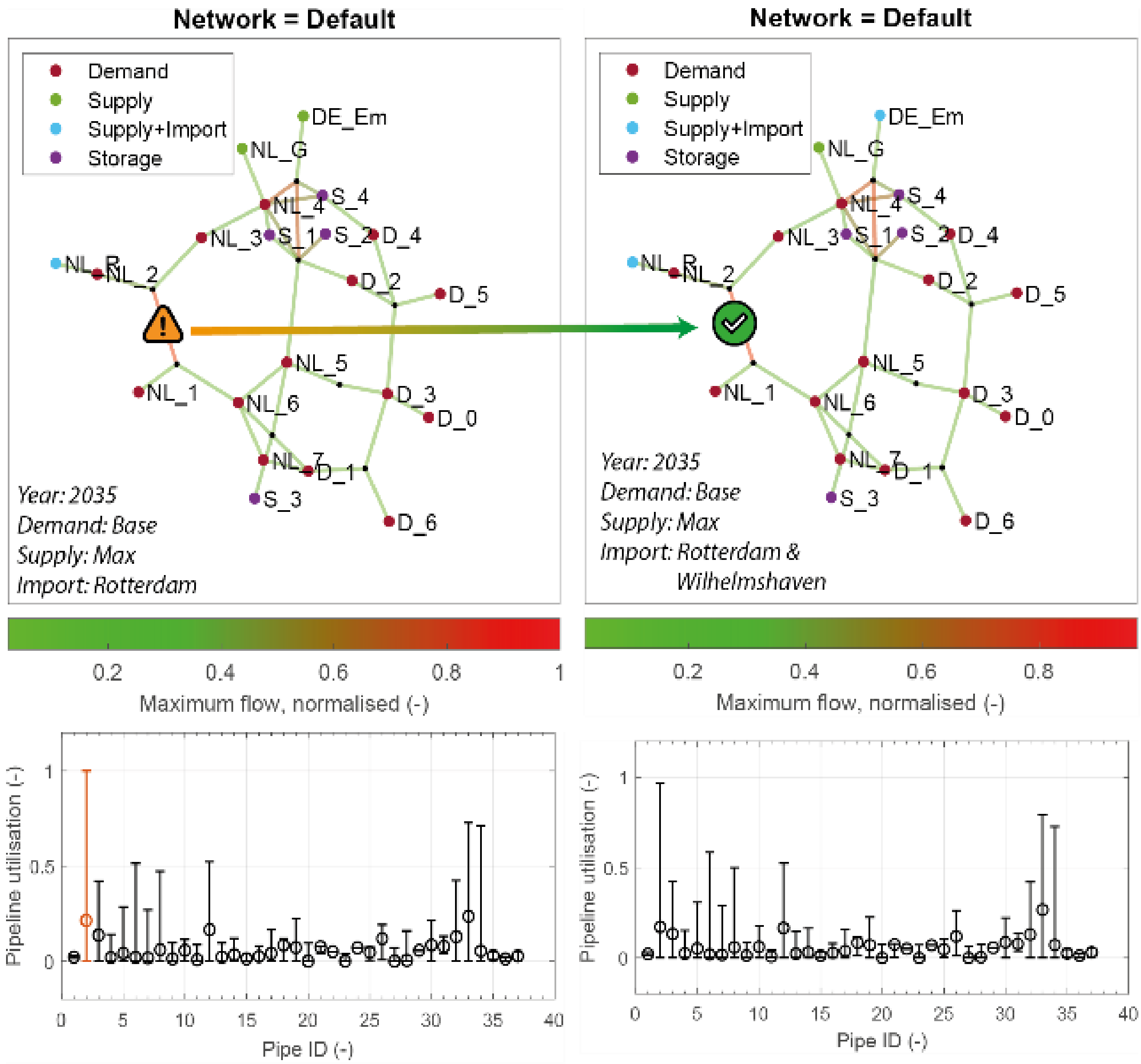

Figure 43: Two scenarios for 2035, baseline demand and maximum supply scenarios highlighting the importance of spreading import from overseas across the network. [left] Simulations with import at the port of Rotterdam showing grid operating at maximum capacity near Rotterdam with orange warning symbol (network diagram) and marking (normalised mean pipe flow plot). [right] Extending simulations shown on the left side with import at the port of Rotterdam and Wilhelmshaven showing grid near Rotterdam is not operating at maximum capacity.

Years 2040 and 2050

The annual demand in the years 2040 and 2050 is projected to increase exponentially, whereas the supply increases linearly from 2030 onwards. This has major consequences for grid utilisation based on existing topology and derived capacity. For instance, in 2050, spreading import over both ports considered in this study (Rotterdam and Wilhelmshaven) would be insufficient to decongest the grid (results in Appendix C4). We therefore assume that the grid is expanded by adding one 48-inch diameter line alongside the entire network[22]. Simulating this scenario, we find that the grid capacity would still be insufficient to transport hydrogen at the projected supply and demand estimates (see left column in Figure 44). As a select scenario, we added the pipe segment (Pipe ID 35, Network = WithRotterdamDEpipe) from the port of Rotterdam to Ruhr (Europoort–Venlo–Ruhr) that is currently used for crude oil transport. In the future, this pipe segment can be replaced for transporting hydrogen. The resulting grid capacity with this expanded network was also found to be insufficient. However, by expanding the capacity of the pipe segment from the port of Rotterdam to Ruhr by one 48-inch diameter line, the grid has enough capacity, but grid utilisation is at a maximum at multiple pipe segments (see right column in Figure 44). These results show that parts of the hydrogen infrastructure require additional measures for resolving bottlenecks, especially around the import connections in these scenarios. Within this study, some of these debottlenecking approaches are explored, but more approaches should be examined to work towards a more optimal rollout of the hydrogen infrastructure. For instance, exploring the role of other import routes and cross-border NL-DE hydrogen grid expansion planning should be further evaluated.

[22] We also simulated a scenario (not shown here) where one extra line was added for pipe segments that are fully utilised. However, this scenario still led to bottlenecks.

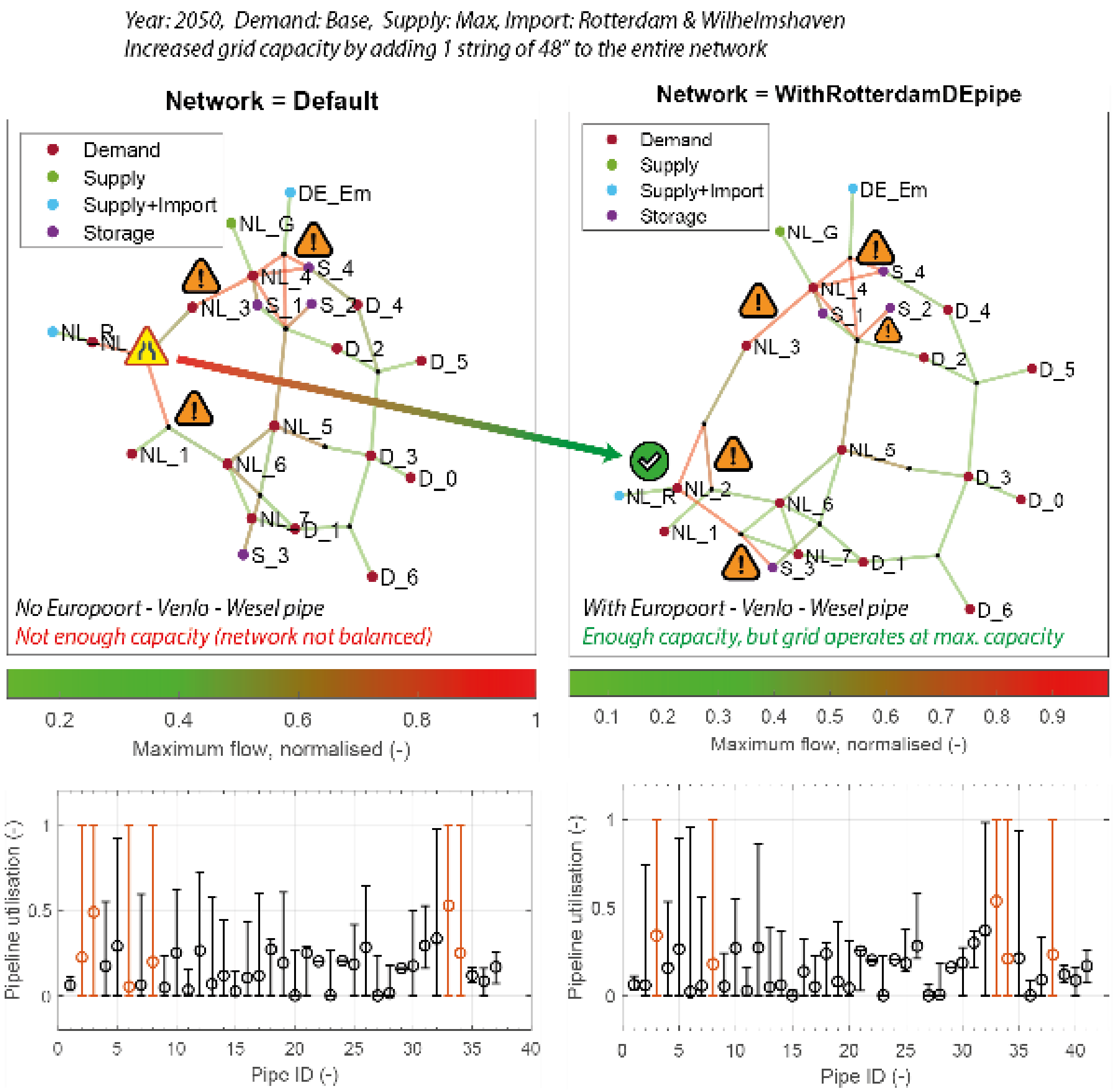

Figure 44: Two scenarios for 2050, baseline demand and maximum supply scenarios highlighting the role of Rotterdam – Ruhr pipeline in decongesting the grid. [left] Simulations with grid expanded using one 48-inch line across the entire network showing that the grid would lack enough capacity. Location of maximum pipeline utilisation and congestion are indicated with an orange triangle and yellow bottleneck symbol. [right] Simulations adding the Rotterdam–Ruhr pipeline expanded using one 48-inch line on top of the left simulation scenario. While grid utilisation is still at maximum at multiple pipe segments, there are no congestions.

6. Hydrogen market potentials and barriers

6.1. Value chains and business models

The emergence of a functioning market is a prerequisite for the realisation of large-scale green hydrogen production in the offshore and coastal regions of the North Sea, in order to be able to supply demand centres in the Netherlands and North Rhine-Westphalia. An assessment of the needed value chains is carried out in this study to evaluate the main aspects for potential business models.

The main aim is to provide an overview of the complex interplay between technical and market aspects. The value chains considered here take into account infrastructure configurations in the scope of the study: hydrogen supply concepts (concept A and B) and hydrogen pipeline transport, hydrogen underground storage, and hydrogen demand (energy or feedstock in industry and mobility sectors). Market functions, energy infrastructure, stakeholders, and a market design are described alongside the value chains. An overview of the status quo for the value chains is shown in Figure 45.

		CONCEPT A	CONCEPT B	**Functions**	**Infrastructure**	**Stakeholder**	**Market design**
1	**Offshore**	●	●	Electricity production and supply	Offshore wind farm	Offshore wind park operator	Competitive (Tender), Incentivised
2	**Offshore**		●	Hydrogen production and supply	Offshore electrolyser	X	X
3	**Offshore**	●		Electricity transmission	Offshore grid	Transmission system operator	Regulated
4	**Offshore**		●	Hydrogen transport	Offshore pipeline	X	X
5	**Onshore**	●		Hydrogen production and supply	Electrolyser	X	X
6	**Onshore**	●	●	Hydrogen transport	Onshore pipeline	Private	Competitive
7	**Onshore**	●	●	Hydrogen storage	Underground storage	X	X
8	**Onshore**	●	●	Hydrogen procurement and consumption as feedstock	Industrial process	Consumer	Competitive
		●	●	Hydrogen procurement and consumption as energy	Industrial process	X	X
		●	●		Filling station	Retailer	Competitive

Figure 45: Status quo of market functions, energy infrastructure, stakeholders and market design for the Hy3 value chains

The following insights could be derived for each part of the analysed value chains:

- Electricity production and supply from offshore wind plays a part in both value chains. Offshore wind farms utilisation on the Dutch and German North Sea is a functioning part of the value chains. Wind park operators access and operate wind parks under conditions set by national laws and regulations that include tendering processes (as described in Section 6.5). Supply of electricity is a competitive activity with a support mechanism in place for some projects, while recent and future projects supply electricity in a free market environment. Main risks include practical realisation of a massive scale-up of offshore wind capacities (as described in Section 4.2) and uncertainties with regard to expected future cost decline of electricity production (as described in Section 4.3.3).
- Offshore hydrogen production and supply is relevant for the value chain with respect to the B variant. Currently, offshore electrolysis is at an early stage of development, hence no practical experience exists. High penetration of offshore wind leads to favourable market conditions for green hydrogen production (e.g. potential benefits of integrated system development of electricity and hydrogen infrastructure, need for flexibility and adequacy, lower overall marginal production cost of electricity). However, the establishment of a regulatory and market design for hydrogen production and supply on the Dutch and German North Sea is a prerequisite. A future regulatory and market design (as described in Section 6.5) needs to recognise synergies with offshore wind markets and address costs and benefits in comparison to direct electrification, among other aspects. It should also address green hydrogen supply competitiveness (see Section 6.3). As part of investigated scenarios, offshore electrolysis comes into play in the mid-term from 2035 (as described in Section 4.3.1).
- Offshore electricity transmission is a part of value chain A. Designated transmission system operators are developing and operating grid infrastructure under conditions regulated by the state and the respective regulatory bodies. Similar to electricity production from offshore wind, main risks include practical and timely realisation of necessary grid infrastructure to support a massive scale-up of offshore wind capacities. Innovative concepts such as hybrid cross-border configurations could come into play.
- Offshore hydrogen transport by pipeline is necessary in case of value chain B. Currently, offshore hydrogen pipelines are not in operation but there is a large number of operating offshore gas pipelines in the North Sea. Cross-border offshore pipeline configurations could be beneficial for project realisation and should be investigated. The same is true for the utilisation of existing gas infrastructure. A regulatory and market design for hydrogen pipeline transport needs to be established together with one for offshore hydrogen production.
- Onshore hydrogen production and supply is a part of Hy3 value chain A. Currently, onshore electrolysis is being tested and demonstrated in numerous pilot projects on a small scale. Beside opportunities mentioned for the offshore hydrogen production, additional renewable energy sources (e.g. solar) and technological synergies (e.g. hydrogen-to-power deployment, utilisation of oxygen as a sub-product) could bring additional benefits. The realisation of a large-scale green hydrogen production from offshore wind and supply on the Dutch and German North Sea coast depends on the future regulatory and market design (as described in Section 6.5). Similar to offshore electrolysis, it needs to take into account synergies with the offshore wind market and address costs and benefits in comparison to direct electrification. It should

also address green hydrogen's competitiveness (see Section 6.3). Onshore electrolysis will be deployed already in the near term as a part of the investigated scenarios (as described in Section 4.3.1).

- Onshore hydrogen transport by pipeline and hydrogen storage in underground caverns is necessary in both value chains. Currently, there are a few hydrogen pipelines used exclusively for feedstock transport in the chemical industry, operating in a non-regulated environment. Underground hydrogen storage is currently being tested. Infrastructure for natural gas is already available and could partially be repurposed in the short term for hydrogen transport and storage. To allow future large-scale transport and storage by (mainly) repurposed gas infrastructure, regulatory and market design needs to be aligned to enable the transition from the current natural gas market (see Sections 5 and 6.5).
- Hydrogen procurement and consumption is the final link in both value chains. Currently, there is limited hydrogen consumption in industry and in mobility from fossil-fuel based hydrogen that is operating in a non-regulated environment (see Section 3). Decarbonisation of the existing demand sectors and adoption in several applications are opportunities for green hydrogen in the relative short term. This includes potential synergies of hydrogen consumption technologies with other P2X technologies, synergies of hydrogen in other sectors, and the advantage of limited to no change in consumption patterns. Additionally, future demand is highly concentrated in the Netherlands and North Rhine-Westphalia, which potentially reduces risks when establishing the whole value chain. Barriers and risks include limited availability of components (industry) and vehicle types (transport), lock-in effects (industry using grey hydrogen, transport using other fuels), high cost-sensitivity of the industry, lack of available refuelling infrastructure, elevated upfront investment for potential new hydrogen consumers and uncertainty of future technological change.

Several conclusions can be drawn from the analysis of the value chains in question. First of all, various preconditions need yet to be ensured in order to enable sustainable business model for large-scale green hydrogen production in the offshore and coastal regions of the North Sea, which can supply demand centres in the Netherlands and North Rhine-Westphalia. Those include bridging the gaps in market functions, energy infrastructure, stakeholders and market design. Opportunities for the future establishment of enabling market conditions include the existing and functioning offshore wind and natural gas market, as well as existing demand for grey hydrogen. To enable a large-scale green hydrogen market in the investigated scenarios, it is necessary to reduce the risks and uncertainties described above. This should include cross-border alignment on market formation and support schemes for early adoption of green hydrogen production and consumption. Policymakers should find a balance between long-term stability, adaptive flexibility and transparency. Complexity and interdependence of those issues brings about the necessity of coordinated, effective and viable plans.

6.2. Total cost of hydrogen supply

This section aims to assess the total costs of hydrogen supply for the supply chains that encompass hydrogen production from offshore wind, transport and storage of hydrogen, and delivery to the demand centres in NRW and the Netherlands. To analyse the total costs, transport and storage costs (LCOT) are added to the levelised cost of electricity (LCOE) and levelised cost of hydrogen (LCOH). This is presented in Figure 46. State levies, taxes and any form of grid utilisation fees are not included in this analysis.

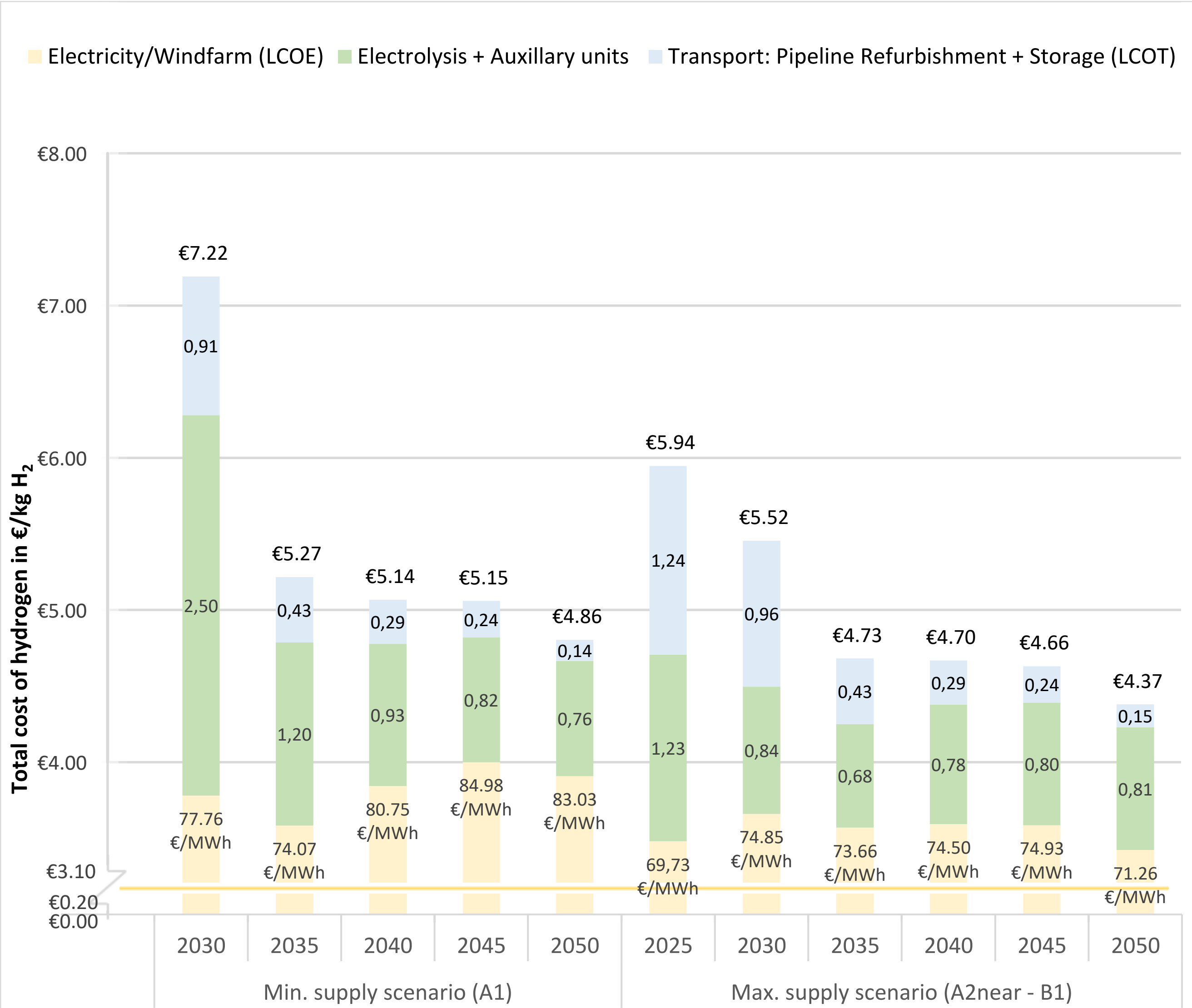

Figure 46: Total cost of hydrogen for min. and max. supply scenarios for each reference year

The total unit costs for the LCOE and LCOH were calculated using the weighted mean of the provided hydrogen quantities to the three feed-in points Emden, Groningen and Rotterdam. The increase in LCOE over time, especially in the minimum supply scenario (A1), is due to several aspects: the decreasing capacity factor results in lower full-load hours, which leads to an increase in the LCOE. This increase is additionally amplified by the development of the more distant offshore areas, as water depth, distance to shore and foundation depth are included in the calculation (a detailed overview of all considered cost components of the LCOE is given in Appendix B1).

The calculation of the LCOT is based on findings from Section 5. The starting point is the pipeline network of over 5,000 km and the number of storage caverns required for the respective supply scenario (see also Sections 5.4.1

and 5.4.2). Medium demand is chosen as the divisor for determining the unit costs. The cost assumptions for pipeline refurbishment are based on the findings of the European Commission's meta-study [65]. The FNB proposal of 0.37 million EUR/km in investment costs is used to determine the refurbishment costs from natural gas pipelines to a dedicated hydrogen infrastructure. The IEA assumption of 17 EUR/MWH$_{H2}$ is the reference for determining the levelised cost of storage (LCOS), which is included in the "transport" section of the bar graph.

Figure 46 shows that high costs for green hydrogen are to be expected, especially in the initial phase of a hydrogen ramp-up. In the case of the minimum supply scenario, H2 costs reach 7.22 EUR/kg in 2030 and, for the maximum supply scenario, costs of over 5.50 EUR/kg for the reference years 2025 and 2030. Infrastructure costs are particularly significant due to the initially low demand. The gradual increase in demand leads to decreasing infrastructure costs. Over time, this leads to costs for the minimum supply scenario of around 5 EUR/kg and, for the maximum supply scenario, to costs well below 5 EUR/kg. In this regard, possible cost recovery instruments should be considered for the initial hydrogen ramp-up to avoid first-mover disadvantages. This could include various forms of direct support mechanisms as well as regulatory adjustments in depreciation and amortisation regulations (e.g. reducing-balance methods).

6.3. Benchmarking cost of hydrogen

A cost comparison between green hydrogen from the North Sea region (scenario A & B) and green hydrogen from other regions in the world was carried out in this study. The results are shown in Comparison of cost assumptions for hydrogen production cost in different studies and publications in Appendix B. This allows for a comparison of cost with selected results from other publications.

For this purpose, a cost range was determined from the three feed-in points Emden, Groningen, and Rotterdam for Scenario A and B in the respective reference years. The MENA region (Middle East and North Africa) was chosen as a comparative reference for green hydrogen, as full load hours and the designated linkage type (via pipeline) are comparable to the Hy3-project scope [66]. The cost ranges for all hydrogen products shown in

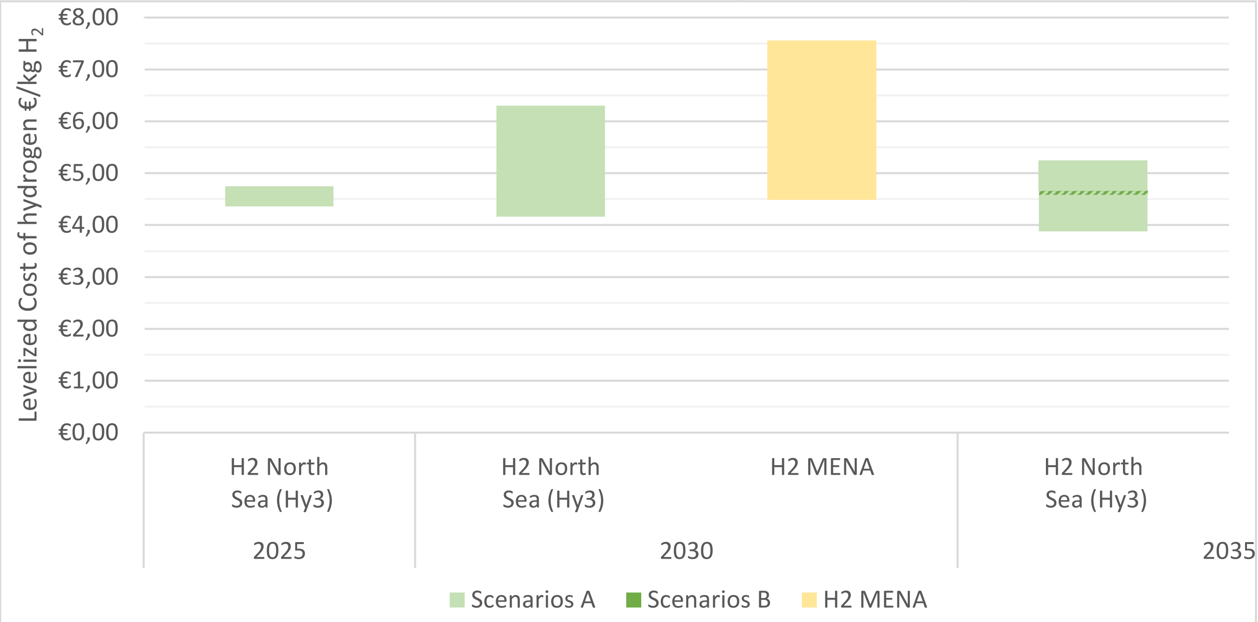

Figure 47 refer solely to the levelised cost of hydrogen and exclude LCOT and other components.

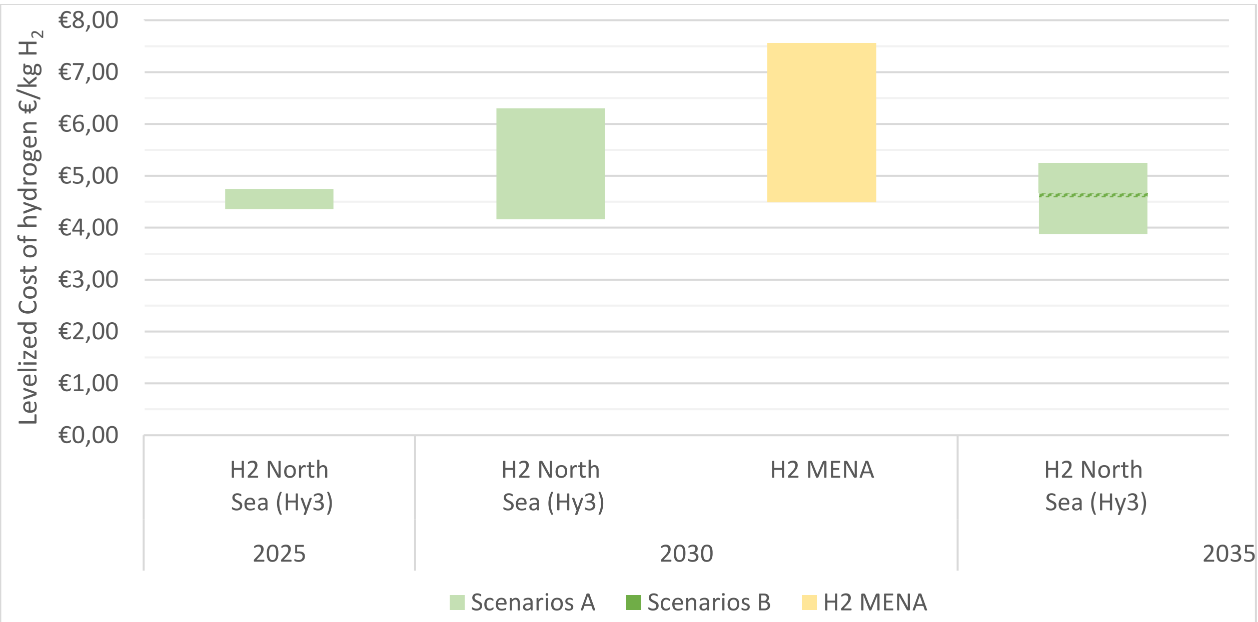

Figure 47: Benchmarking green hydrogen from scenario A, B and the MENA region

Green hydrogen from the North Sea region converges by 2035 at costs between 3.90–5.30 EUR/kg. The levelised costs of green hydrogen from the North Sea become more and more consistent due to larger production volumes, increasing full-load hours and the expansion of offshore wind and electrolysis capacities in the North Sea. Compared to the levelised costs of hydrogen from the MENA region, the costs are advantageous at the beginning and remain competitive over time. The resulting LCOH are relatively high compared to the literature values because a different approach and different assumptions were used here. In particular, the LCOH in this study includes associated costs for transporting electricity or hydrogen to the coastal feed-in points. A comparison of LCOH cost assumptions is available in Appendix B2.

Apart from the import of a carbon neutral hydrogen, significant quantities of low carbon hydrogen could be supplied in the form of blue hydrogen. Blue hydrogen is produced via the utilisation of natural gas reformation (NGR) with sequestration and carbon capture and storage (CCS) (see also Section 4.4). Such low carbon hydrogen could be produced in the region, possibly from produced or imported natural gas. Other options could be to produce it in the gas export countries and then import it to the region via pipeline or ship. Blue hydrogen production technology is yet to be exploited on a large scale and the potential production costs are being intensively discussed in the literature.

For the purpose of this analysis, costs of blue hydrogen production are calculated using the EWI Excel tool "Estimating global long-term supply costs for low-carbon hydrogen from renewable energy sources and natural gas" [67]. These are determined on the basis of the deposited IEA dataset (e.g. European gas price development projected by the IEA, additionally varied by a premium/discount of 25%). The resulting cost levels are in the following ranges: 2.05–2.60 EUR/kg in 2025, 2.19–2.76 EUR/kg in 2030 and 2.24–2.78 EUR/kg in 2035. The calculation of the longer term trends for the levelised cost of blue hydrogen results from the assumptions of declining natural gas prices, declining CAPEX costs as a result of further R&D and rising CO_2 prices (assumed at 59 EUR/tCO_2 in 2025, 88 EUR/tCO_2 in 2030 and 110 EUR/tCO_2 in 2035. It is worth noticing that the cost of CO_2 transport and storage is not included in the blue hydrogen production cost. Figure 48 shows cost components of blue hydrogen production in 2030.

This study did not take a closer look at other aspects of potential blue hydrogen production and supply. For example, in terms of the cost aspect, more ambitious CO_2 pricing strategies could influence the cost ranges described above in the future. The same is true in the case of an upward development of natural gas prices in contrast to the declining trend assumed by the IEA. Logistics and costs of CO_2 transport and storage could also play a role in assessment of specific use cases. Furthermore, an issue of methane leakages in the course of natural gas exploration and transport value chain is yet to be thoroughly addressed by policymakers. Finally, the advantages of domestic energy production and public acceptance need also to be taken into account. In this respect, further investigation is needed for a comprehensive analysis and benchmarking of various hydrogen production technologies and value chains.

As stated above, these cost assessments allow for a comparison of results from other publications. It then becomes clear that cost estimates for production of green and blue hydrogen, as well as import of low carbon hydrogen are highly subject to uncertain assumptions. These originate mainly from the uncertain cost projections for dominant cost factors. We already showed that for green hydrogen production in Germany and Netherlands, the full-load hours, capital cost assumptions for the electrolysers and electricity costs from offshore wind dominate the outcome of the levelised cost of hydrogen. Under the assumptions in this study, the prices for green hydrogen converge at 4–5 EUR/kg. For blue hydrogen we see cost estimates between 2–3 EUR/kg in 2035. The key uncertainties for this source of hydrogen are the year of the cost estimate, natural gas price, cost of CCS and the CO_2 price, which are still uncertain. For natural gas and CO_2 emission certificates (under the ETS), we see high price variability in recent years, and short- and long-term projections are therefore highly uncertain.

The literature also recognizes this large range in cost estimates. Green hydrogen costs range between 1.1 and 4.1 EUR/kg (see Appendix B2 for a comparison of several sources). This indicates that the capital costs for electrolysers, the load factor (electrolyser and offshore wind) and LCOE assumptions for offshore wind used here are quite conservative. All such conservative assumptions lead to higher cost estimates for green hydrogen production in comparison to selected literature sources. It is not justified from this perspective to make strong conclusions on what the exact price of hydrogen will be. However, there is a clear downward cost trend for green hydrogen production in Germany and Netherlands and it is expected to become competitive with blue hydrogen production and import – however, highly dependent on the prevailing and future commodity prices.

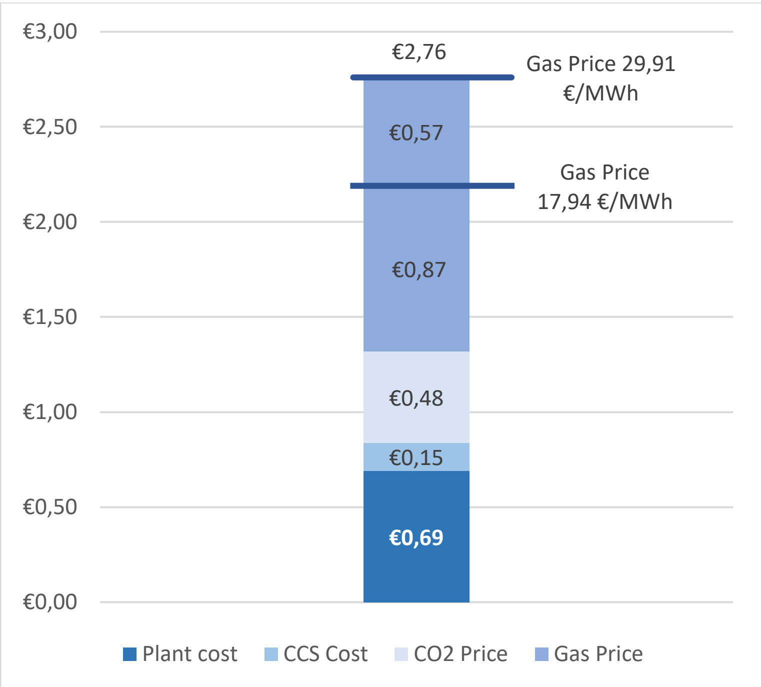

Figure 48: Cost components of blue hydrogen in reference year 2030

6.4. Possible transition pathways for developing an international hydrogen backbone

6.4.1. Developing an international hydrogen backbone – setting the context

Legitimacy
The EU has set ambitious targets for developing hydrogen before 2030 in its Hydrogen Strategy and Energy Integration Strategy[23]. An important element for regional, national and international developments towards achieving these goals is the social justification for developing a hydrogen infrastructure. This is not self-explanatory for all stakeholders involved. Creating long-term legitimacy for this activity as soon as possible is paramount to ensure that these actions are publicly validated and endorsed (see Dacin et al. (2007) and Rao et al. (2008), for example [68, 69]). Legitimacy needs to be created for both the hydrogen backbone concept as a whole, as well as for the individual infrastructural elements it consists of (demand clusters, transmission pipelines and distribution networks, storage sites, compressors, etc.) to prevent project delays affecting the critical development path. Additionally, sector coupling of hydrogen and electricity markets (offshore wind, offshore and onshore electricity grid expansion) will have to be addressed in the planning process. This could be a coordination of infrastructure development but also a wider, integrated energy system approach when assessing costs and benefits.

A clear benefit of an internationally connected hydrogen infrastructure is that it enhances energy system flexibility and security of supply. In the case of pipeline failure or outages, the sketched infrastructure has alternative routings to transport the hydrogen. Overall, pipeline transport capacity can be better planned, resulting in a better use of the network. In the case of hydrogen storage outages, other storage sites can take over this function. If one hydrogen source shows bottlenecks, then other supply routes can balance the system (i.e. multiple import route entry points). A more extensive infrastructure also increases the amount (and volume) of demand sectors and clusters, most likely resulting in more demand side flexibility. Consequently, a larger network with better interconnections is expected to have a higher resilience.

The backbone
This study outlines an envisioned backbone topology based on visions from national hydrogen developments in both the Netherlands as well as specific regions within Germany. The concept that TSOs are currently pursuing is to use current hydrocarbon infrastructure and convert it where possible [70, 71]. This approach is also the starting point of this study. Hydrogen storage is also assumed to be part of this initial infrastructure in the form of subsurface cavern storage. In the future network the demand clusters are geographically situated around existing industrial clusters and nodes. The landing points for offshore hydrogen production, onshore hydrogen production locations, or overseas import hubs (Rotterdam and Wilhelmshaven in this study) are important "new" hubs for the development needs of the transport infrastructure. This sets an important framework for the evolution of the network.

[23] Green hydrogen production capacity may reach 40 GW by 2030, as stated in the European Hydrogen Strategy.

A key question is to determine to what extent current natural gas transport capacity can be made available for dedicated hydrogen transport while natural gas transport is still necessary. Section 5.2 discusses this in more detail. For this study, it is assumed that parallel pipeline segments can be made available for hydrogen transport. If at least one pipeline line is available on the backbone route, then hydrogen transport capacity is not likely to become a bottleneck in the early years. Yet, this depends strongly on the demand and supply estimates and assumes certain operating conditions of the pipeline network (i.e. flow velocity and pressure).

Critical path

The timing of transitional pathways towards a dedicated hydrogen backbone is of high interest to all parties involved. Some elements of the backbone can be achieved in short time frames (years), while many elements can take several years from initial feasibility study to commercial operation. Examples from natural gas storage projects and pipelines show that the preparation phase including feasibility assessment, investment decision and permit phase can take several years for large-scale infrastructure elements (see **Table 7** for indicative ranges of lead times). The conversion to hydrogen pipelines comes with additional challenges, because hydrogen demand and supply volumes as well as natural gas transport obligations (as the important framework) affect the availability of certain pipeline segments.

The preliminary analysis in this study indicates that network congestion can occur. If it does, it will do so in situations near import and production hubs that need to cope with high temporal flows in certain periods of the year. The network can also become congested if for certain parts of the network just one pipeline line (in the case of parallel lines) can be made available for dedicated hydrogen transport. Then congestion may occur in scenarios with high demand and supply. Possible network congestion occurs from 2035 onwards. In this period, natural gas still has an important role to play in the Dutch and German energy systems, even if hydrogen supply and demand is growing quickly. Roughly 15 years between now and 2035 provide sufficient time for strategic planning under multiple and uncertain scenarios, but action is warranted now. It is critical to already highlight which legacy infrastructure is of high value to a possible future hydrogen backbone. This can help the design of a network topology at an early stage and to earmark legacy pipelines and storage locations for hydrogen transport and storage. This could already inform strategic spatial planning decisions on the regional, national and international level and limit critical delays in the period from 2030–2040.

Table 7: Indicative development timelines for key infrastructure elements for a hydrogen backbone (estimates based on [72, 73][24])

Infrastructure elements*	Years							
	1	2	3	4	5	6	7	8+
Pipeline refurbished								
Pipeline new								
Gas storage cavern green field								
Gas storage new cavern brown field								
Gas storage reuse cavern brown field								
Gas storage depleted gas field								

[24] TNO own estimates

Compressor		

Against this background, possible transition pathways are outlined for the next decades, with each period showing its own characteristics and challenges.

6.4.2. Possible transition pathways towards an international hydrogen backbone

The 2020s: from initiation to first realisation

In the period up to 2030, the area under study is assumed to convert minimally ca. 3,000 km of natural gas transport pipelines and establish about six caverns for subsurface hydrogen storage. The backbone will be largely established at the end of the twenties, but supply and demand clusters are still in a transition phase. Hydrogen demand from early adopters in the industry and other sectors is matched by supply from offshore wind and import from overseas. The challenges for this decade are: the development of a blueprint for the years to come, establishing legitimacy, the initiation of strategic spatial planning across borders, the creation of an integrated market and the removal of institutional challenges.

Technical transport and storage capacity are not a weak link on this path. Cross-border capacity is already planned for a new connection between Vlieghuis and Kalle which will be ready for operation in 2025, as well as a conversion of a pipeline at the border connection Elten/Zevenaar, which will be ready for operation in 2030 (see maps in Section 5.2.1). However, a sustainable business case given the expected low initial utilisation rate of the established network will be of interest.

The 2030s: growing demand and supply for green and low-carbon hydrogen

In the period from 2030 to 2040, the main challenge is to achieve large growth towards 126 TWh (range: 76–177 TWh) of annual demand. To facilitate this large-scale growth supply chain constraints have to be removed. These constraints can be market factors in offshore wind, hydrogen production and import, but also in the demand sectors that hamper wide-scale adoption of hydrogen against the backdrop of possible alternative routes for decarbonisation.

Technical transport and storage capacity are expected to become limited only in the case of high demand and if certain parallel pipeline sections (or sections that do not have parallel pipelines) cannot be made available in time for dedicated hydrogen transport. This period sees the first transitional challenges of moving from natural gas to hydrogen. A complex and interdependent combined grid planning for hydrogen and natural gas is warranted for this period and onwards to start making available pipelines (existing or new) for hydrogen transport. Most likely this decade is dominated by uncertainty about the rate of decline of natural gas consumption.

The 2040s: steep growth towards maturity

In the period from 2040 to 2050, the main challenge is to maintain the large growth spurred in the thirties, pushing it further towards 401 TWh (range: 240–547 TWh) of annual demand. With more than 5,000 km of converted natural gas pipelines and almost 60 hydrogen storage caverns, the market should have reached maturity, enabling international trade and price setting across borders on a wide scale. Green and low-carbon hydrogen production and consumption is assumed to be commercially sustainable.

The transport and storage infrastructure requires the removal of bottlenecks around the most import connections. In certain periods the capacity of the backbone is put to the test. But ample time is available up to 2040 and onwards to see early warning signs for transport and storage bottlenecks and adjust strategic planning accordingly and to expand transport and storage capacity.

Orchestration: coordination and guidance

The illustration of this transition pathway shows that large uncertainties about the future rollout of hydrogen infrastructure in north-west Europe still persist. A very high level of coordination and guidance is needed to realise the ambitious cross-border hydrogen backbone visions over the next decade(s). To add to the challenge, coordination and guidance is required on all infrastructural elements of the hydrogen backbone to overcome multifaceted technical, market, regulatory and societal challenges.

6.5. Regulatory framework

A suitable regulatory framework is necessary in order to establish the supply chains presumed in this study. Power-to-gas facilities, pipelines and underground storages for hydrogen are yet to be utilised on a large scale. There are various uncertainties regarding the legal treatment of the infrastructure in question – also regarding the market rules under which they will operate in the future. The following sections focus on the regulatory framework for specific aspects of a hydrogen market, including production from offshore wind, transport and storage operations. How these aspects currently fit into European and national regulations, foreseeable developments, and what could be done to tackle the uncertainties and regulatory gaps are addressed in this section.

6.5.1. Hydrogen production from offshore wind

Hydrogen supply concepts taken into account in this study (see Section 4.1) include onshore and offshore electrolysis (power-to-gas facilities), offshore electricity grid and subsea hydrogen pipeline infrastructure. Theoretical infrastructure configurations are positioned in the North Sea Exclusive Economic Zone (EEZ), and in the case of offshore electricity grid and subsea pipelines, also in the territorial waters[25] of the Netherlands and Germany. Cross-border infrastructure is not considered for the assessment of the hydrogen production potential, but this could make technical and economic sense in a project-specific environment and should thus be taken into account.

Both the Netherlands and Germany have an established and functioning regulatory framework for offshore wind markets, while the rules for power-to-gas facilities are still to be fully developed and implemented. However, in the context of future developments, adjustments to the regulatory framework both for offshore wind and for the hydrogen sector are already under discussion or in the early phase of implementation. Those developments include a rapid and massive scale-up of offshore wind capacities, fostering of innovations[26] for reaching overarching decarbonisation goals, spatial planning, environmental protection, etc.

[25] Twelve nautical miles from coast

[26] E.g. offshore hydrogen production, hybrid offshore projects with cross-border infrastructure, energy islands and other emerging technologies and concepts.

Regulation at the European level

An ambitious vision of large-scale deployment of renewable hydrogen electrolysers is envisaged for the European Union. It is recognised that to drive hydrogen development past the tipping point, an enabling regulatory framework will be required, as expressed in "A hydrogen strategy for a climate-neutral Europe" [74]. A particular challenge in large-scale deployment of power-to-gas facilities lies in the fact that sector coupling of the electricity and gas sector, in terms of their markets and infrastructure, still lacks a suitable legal framework within European Union legislation. A comprehensive overview of technological and regulatory gaps and barriers for sector coupling is described by the European Commission's report [75]. One of the central questions with regard to regulation of power-to-gas facilities is their legal classification. It is essential to clarify their status: as end consumer of electricity, gas producer, power-to-energy storage/gas storage and/or fully integrated network component [76]. The EU Directive on common rules for the internal market for electricity prescribes conditions for energy storages and fully integrated network components, but further clarifications are needed (ibid.) [77]. In this regard, the EU Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) have made recommendations on how to regulate power-to-gas facilities and stipulate a necessity for [78]:

- Revision of definitions for major activities in the context of integrated gas and electricity sectors
- Treatment of investment and management of the facilities as market based activities
- Limitation of system operator's role only to exceptional cases
- System needs analysis when deciding on installation and location
- Definition of cost-reflective network tariffs
- Avoidance of distortive effects of taxes and levies
- Insurance of traceability of renewable energy

These issues need to be tackled within the transposition of the EU Directive on common rules for the internal market for electricity and in the establishment of a revised regulatory framework for competitive decarbonised gas markets, which is envisaged for the second half of 2021 [79].

Connecting coastal or offshore power-to-gas facilities to an offshore wind electricity source brings additional complexities. "An EU Strategy for Energy System Integration" proposes key actions for energy system integration [27][80]. Among others, the strategy aims to ensure continued growth in the supply of renewable electricity and follow-up regulatory and financing actions, the cost-effective planning and deployment of offshore renewable electricity, taking into account the potential for on-site or nearby hydrogen production, and strengthening the EU's industrial leadership in offshore technologies. Furthermore, "An EU strategy to harness the potential of offshore renewable energy for a climate neutral future" outlines a framework for utilising offshore potentials in the context of planning, investment barriers, the regulatory framework, private sector investment and EU funds, research and innovation, and supply and value chains [37]. The strategy clarifies the regulatory framework, announces future steps

[27] Defined as the coordinated planning and operation of the energy system "as a whole", across multiple energy carriers, infrastructures, and consumption sectors

in view of amendments and revisions of legislation[28] and announces guidance on cost–benefit sharing for cross-border projects [81].

Regulation at the National level

The German National Hydrogen Strategy announced a plan for establishing hydrogen generation capacity from offshore and onshore energy generation facilities [37]. Furthermore, the strategy announced cooperation with North and Baltic Sea Border nations to push forward hydrogen production by establishing a reliable regulatory framework for offshore wind energy. Currently, numerous power-to-gas facilities are already operating as demonstration or pilot projects[29]. However, several uncertainties and regulatory gaps for a large-scale deployment need to be considered. Power-to-gas facilities are classified as end electricity consumers due to a lack of definition and are thus burdened with a renewable energy surcharge, which is paid by electricity consumers to finance the rollout of renewable electricity generation. Recently adopted amendments of the Renewable Energy Law (EEG) add specific provisions[30] in view of partly or fully removing the obligation to pay the EEG surcharge on the electricity used for the electrolysis process [82]. Following a classification as an "installation storing electrical energy", power-to-gas facilities with a capacity greater than 100 kW are obliged to provide redispatch services. However, classification as a form of "electricity storage" is not entirely certain [74]. Furthermore, there is the issue of legal qualification as "green electricity" of electricity used by a power-to-gas facility while connected to the offshore transmission grid and the resulting qualification as "green hydrogen" of the hydrogen produced. This issue can be tackled either by demonstrating that dominantly renewable electricity was used in hydrogen production due to the direct connection to the offshore transmission cable or by otherwise certifying renewable origin of the electricity [83]. Another uncertainty[31] to be considered is the necessity for a power-to-gas facility to obtain an authorisation pursuant to the Federal Emissions Protection Act, which includes comprehensive administrative procedures including public participation [84].

An offshore wind market in Germany is well-established. The Federal Maritime and Hydrographic Agency (BSH) is responsible for the development of areas in the German North and Baltic Sea EEZ for the construction and operation of offshore wind farms based on the Wind Energy at Sea Act [85]. Winning a competitive tender procedure for offshore wind farms (OWFs), organised by the Federal Network Agency (BNetzA), is a prerequisite for a planning permit and the right to feed the electricity produced into the national grid.

A possibility to produce hydrogen offshore with no grid connection in the so-called "other energy generation sectors" (*sonstige Energiegewinnungsbereiche,* OES) was introduced in the law. The authorisation to install OWFs in these sectors will be conditional on an award in a tendering procedure, which is yet to be proposed and adopted [86]. According to the latest area development plan, a single area in the North Sea – SEN-1 – is designated for this

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[28] With regard to allocation of congestion income with regard to offshore hybrid projects, grid connection network codes for offshore high-voltage direct current grids and state aid guidelines for environment and energy.

[29] Overview of projects available at https://www.kopernikus-projekte.de/projekte/p2x/ptx_anlagen

[30] Will be further specified by a regulation of the Federal Government, in order to define conditions for qualification of hydrogen production as "green" with regard the origin of the electricity used for the electrolysis. Also, the new EEG 2021 has been designed by Germany as a state aid mechanism and requires a notification procedure to the EU Commission.

[31] Legal interpretation is being disputed among legal experts

purpose (e.g. for offshore wind turbines and a power-to-gas facility) and there is the possibility of further areas for the longer term[32] [40]. However, the area development plan has ruled out the possibility to connect SEN-1 to the shore by cable or pipeline. In this regard, it is evident that spatial planning, in terms of available areas for offshore hydrogen production and for the transport infrastructure, are regulatory insecurities that need to be considered. In the case of construction and operation of subsea interconnector cables and hydrogen pipelines, approvals with regard to mining aspects with the regulations on use of waters above the continental shelf, as well as the air space above these waters are required in accordance with the German Federal Mining Act. The option of a direct (merchant) cable for supply of a power-to-gas facility on land can be challenging from a legal perspective. Finally, planning and construction in the territorial waters are subject to the planning regime established by the Offshore Installations Act and the regional planning procedure of the relevant federal state needs to be followed. A comprehensive overview of applicable legal acts and procedures for planning and constructing offshore infrastructure is available in the report[33] from the North Sea Wind Power Hub project.

The Netherlands vision for the large-scale application of hydrogen production (and use) was laid out in the government strategy on hydrogen and states that apart from stimulating hydrogen, further and accelerated development of offshore wind energy is an important part of the country's climate protection ambitions [50]. With regard to a power-to-gas facility regulation, there are uncertainties that need to be tackled – similar to those in Germany. Current gas definitions in the Netherlands do not include hydrogen, which has wider implications for the application of existing gas related regulation to power-to-gas facilities, e.g. with regard to the organisation of network access and feed-in [76]. Furthermore, uncertainties exist with regard to the classification of the power-to-gas facility as end or wholesale electricity consumer, relevant for obligations to pay electricity network rates, taxes and levies [ibid].

An offshore wind market in the Netherlands is also well-established and the regulatory framework is stipulated through the Offshore Wind Energy Roadmap, the Climate Agreement, Wind Farm Site Decisions and permits issued under the Offshore Wind Energy Act, the Stimulation of Sustainable Energy Production Decision (for subsidies, if necessary) and the Development Framework for the development of offshore wind energy [29]. The Netherlands Enterprise Agency (RVO) is commissioned by the Ministry of Economic Affairs and Climate Policy for the development of areas in the Dutch North Sea EEZ. A comprehensive overview of applicable legal acts and procedures for planning and constructing offshore infrastructure is available in the report[34] from the North Sea Wind Power Hub project.

A regulatory framework for offshore hydrogen production is currently lacking, but announcements and discussions on necessary adjustments are ongoing. Among others, it has been announced[35] that a revision and integration of

[32] Taking into account the update of spatial planning (Flächenentwicklungsplan 2020, p. 124)

[33] Planning & Permits Study, German EEZ, FINAL REPORT, North Sea Wind Power Hub, 1 Jul. 2019

[34] Planning and permitting study – The Netherlands, North Sea Wind Power Hub, 23 May 2019

[35] Letter to Parliament Progress of implementation of the 2030 Offshore Wind Energy Roadmap, Minister of Economic Affairs and Climate Policy

the 1998 Electricity Act and the Gas Act into a new Energy Act should allow offshore mining platforms to be connected to the grid. It is also envisaged that a review of the need for an adaptation of the applicable law concerning offshore grids, in consideration of any direct connections to the grid for industrial customers, conversion installations (e.g. power-to-gas), oil and gas platforms (electrification) and CCS installations, will take shape within the framework of the legislative agenda. An updated overview on technical possibilities and economic opportunities for increasing the sustainability of energy supply from the North Sea in the period 2030–2050, the North Sea Energy Outlook[36], is presented in a recent publication. In the associated letter, the Minister, among others, concludes that large-scale onshore electrolysis combined with offshore wind energy is achievable by 2030. Furthermore, it was announced that several models for joint tenders for offshore wind energy and hydrogen production are being assessed.

6.5.2. Legal definition and certification of green hydrogen

There is currently no clear legal definition of green hydrogen on EU and national level. This, however, is a necessary prerequisite for its large-scale deployment. In Germany, the current definition of hydrogen as "biogas" if it was produced via electrolysis using "predominantly" renewable electricity will be adjusted [87]. Instead it will be defined as an energy carrier, as proposed in amendments of the Energy Industry Law from January 2021 [88]. In the Netherlands, hydrogen is not considered a gas under the definitions of the Dutch Gas Law.

An additional prerequisite for a functioning national and international large-scale market of green and low carbon hydrogen is the establishment of a certification system. Such a system should make it possible for producers to be able to demonstrate the origin of the energy used to produce the renewable hydrogen regardless of the location. It is important to provide a distinction to consumers between low-carbon and green hydrogen and hydrogen produced through more carbon intensive pathways and to allow monetisation of renewable quality of hydrogen. There is an established system of guarantees-of-origin (GO) certificates for electricity, stipulated by the Renewable Energy Directive [89]. The issuance, trade and cancelation of certificates are standardised through the European Energy Certificate System (EECS), which is organised by the Association of Issuing Bodies (AIB). However, there is no such standardised European system for renewable gases and Member Countries have various national systems that are only partly interconnected and are based on voluntary agreements [90]. Furthermore, in the case of electricity, there is no connection between the physical trade of the underlying commodity and the certificate trade, while the systems in the gas market rely on the mass-balancing approach coupled to the physical flows of the underlying energy commodity [ibid.]. As the current renewable gas certification systems were designed with regard to deployment of biogas for electricity production and production of biomethane to be fed into the natural gas grid, they are not suitable for the future green hydrogen market. Although provisions[37] of the Renewable Energy Directive allow the possibility for hydrogen GOs, they contain no technical provisions regarding the nature of a possible hydrogen GO certificate and they will need to be significantly revised and updated to introduce hydrogen-specific GOs [91]. The EU hydrogen strategy announces EU-wide instruments that would, among others, include

[36] Letter to parliament North Sea Energy Outlook, Minister of Economic Affairs and Climate Policy, 4 Dec. 2020

[37] Article 19(7) (b)

common comprehensive terminology and European-wide criteria for the certification of renewable and low-carbon hydrogen. It notes that the specific, complementary functions that GOs and sustainability certificates already play in the Renewable Energy Directive can facilitate the most cost-effective production and EU-wide trading.

In that respect, the implementation of the of the revised Renewable Energy Directive (RED II) and accompanying technical rules envisaged for July 2021 will be a crucial step in addressing the regulatory uncertainty of green hydrogen definition and certification on EU level [92].

6.5.3. Hydrogen pipelines and underground storage

Hydrogen transport and storage concepts taken into account in this study (see Section 5.1) include hydrogen pipelines and underground storage infrastructure (specifically in salt caverns) in the Netherlands and north-west Germany. Cross-border pipelines are a necessary part of the supply and delivery route.

There are no substance-specific rules for hydrogen transportation at European level specifically. European regulations regarding hydrogen transport are application-specific, such as the directives on pressure equipment (2014/68/EU) and equipment for potentially explosive areas (ATEX 94/9). Both Germany and the Netherlands have already developed 100% hydrogen pipelines under current regulations. These are currently point-to-point pipelines, and more extensive developments of the pipeline network would be required in order to form a hydrogen grid.

There are three operating hydrogen pipelines in Germany run by Air Liquide (240 km long in the Rhine-Ruhr area), by Heide Refinery (30 km long in Heide) and by Linde (100 km long, in Leuna) [95]. In the Netherlands, there are two hydrogen networks operated by Air Liquide and Air Products. Air Liquide operates the largest hydrogen network, with over 1,000 km, connecting hydrogen producers and consumers in France, Belgium and the Netherlands. These networks are designed specifically to the bilateral contracts of these parties [96].

One example in the Netherlands of potentially prohibitive legislation is that hydrogen transport is currently classified as chemical piping and therefore falls into a different module within the Dutch "External Safety Pipelines Decree" in comparison to natural gas. This classification means that hydrogen falls into a higher risk category[38]. The current regulation therefore advises to have calculations carried out to quantify the risk, taking into account the difference in consequences of natural gas and hydrogen outflow. These regulatory aspects must be resolved before a large-scale use of hydrogen can replace natural gas in the Netherlands[39] [94].

Hydrogen production, transportation and end use are likely to become more decoupled (forming grids rather than point-to-point pipelines) in the long-term. For the development of a large commercial-scale hydrogen gas network (with numerous hydrogen sources utilising the same network), more explicit hydrogen regulations are required at both national and European level, similar to those already developed for natural gas. The 2021 White Paper by ACER and CEER highlights that these existing business-to-business pipelines should not be impacted by future regulation regarding hydrogen networks [78]. They recommend that the regulatory framework should be clarified

[38] This is mainly due to there being less long-term experience handling hydrogen pipelines, which impacts the statistical risk analysis.

[39] DNV GL and The Dutch Ministry of Economic Affairs undertook an assessment of current hydrogen infrastructure in the Netherlands, which included a review of regulatory aspects regarding the potential to add hydrogen to the existing gas system.

from the outset for private hydrogen networks that are constructed as business-to-business networks and that temporary exemptions to future regulation may be explicitly foreseen in the forthcoming EU legal framework. This will avoid that point-to-point pipelines are unnecessarily impacted, while ensuring that those exemptions are given under the same EU regulatory framework.

Reuse of natural gas pipelines

The proposed Hy3 hydrogen backbone pipeline network (as described in Section 5.2) is largely based on existing natural gas pipeline corridors and infrastructure. The current regulatory framework surrounding the reuse of existing natural gas pipelines will therefore play a major role in the establishment of hydrogen supply chains as presumed in this study.

There are no cases of the reuse of natural gas pipelines for use with pure hydrogen in Germany to date, but intensive activities are being carried out in this regard. Gas transmission system operators have already proposed a concept for integrating green gas[40] pipelines as a part of a network development plan [97]. The proposed pure hydrogen network envisages 471 km of pipelines by 2025 – consisting of 83% repurposed gas infrastructure – and 1,236 km by 2030 – consisting of 88% repurposed gas infrastructure [ibid.]. To allow the development of such a hydrogen backbone, a necessary regulatory framework is still to be established. In this regard, a recent proposal of amendments to the Energy Industry Act includes a transitional regulation on the regulatory treatment of pure hydrogen networks that aims to set a framework for a speedy and legally secure start to the gradual development of a national hydrogen network infrastructure [97]. Furthermore, the Federal Network Agency (BNetzA) accepted operators' 2020–2030 grid development plan with several requests for changes, allowing the pipelines to be taken out of the current natural gas infrastructure and added to a future hydrogen grid, provided that the performance of the current gas grid is left uncompromised [98].

The reuse of natural gas pipelines for the transportation of hydrogen has been permitted in the Netherlands under current regulations. A previously state-owned (Gasunie) 12 km long natural gas pipeline has been repurposed for hydrogen transportation (from Dow to Yara), transporting four kilotons of hydrogen per year. The pipeline is now operated privately by Gasunie New Energy rather than Gasunie because hydrogen is not considered a gas under the definitions of the Dutch Gas Law, thus preventing the hydrogen pipeline from being operated as part of the regulated activities of gas system operators [100]. The Dutch government is currently investigating the role Gasunie will have in the future hydrogen supply chain [99]. For more commercial large-scale developments, hydrogen specific standards and regulations would be beneficial in an effort to provide clarity on the differences between operating natural gas and hydrogen within a repurposed pipeline. Gasunie recently provided feedback on the EC's "Hydrogen and Gas Markets Decarbonisation Package", stating (regarding hydrogen transmission) that several issues still need to be clarified [101]. Firstly, that in certain cases an (administrative) transfer of assets within companies will be needed to ensure maximal efficiency between shared services (i.e. between the natural gas and hydrogen operations within the infrastructure operator). A second issue that needs to be addressed is ensuring the rights of way that need to remain applicable after repurposing infrastructure from natural gas to hydrogen.

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[40] Hydrogen, synthetic methane and biogas

The European Commission is expected to propose a new legislative package containing more widespread reforms for the gas sector in Q4 of 2021. This gas decarbonisation package is expected to revise the gas market design and enforce renewable gases' role in the European market.

Cross-border pipeline transport

The requirements for a transitional pipeline between Germany and the Netherlands would be defined under national laws and regulatory requirements, given the lack of hydrogen-specific pipeline regulation at European level. For the onshore pipeline transportation of hydrogen the gas composition standards and operational regulations would currently be regulated at national level. It would be more comprehensive and more conducive to future cross-border investments to implement uniform standards and common principles in place at European level through which national standards and therefore projects can be guided. Otherwise, varying regulations at national level require the project investor to comply with multiple regulatory requirements [99].

The EU policy framework does however provide enabling measures and co-funding (e.g. TEN-E and CEF funding) to develop investment in gas infrastructure that will have a cross-border impact. A proposal for revisions to the TEN-E regulations was published in December 2020, which has an increased focus on low carbon gases, including hydrogen. To support the decarbonisation needs of the hard-to-abate sectors, the revisions proposed will include "*dedicated new and repurposed hydrogen networks with cross-border relevance (including hydrogen transmission pipelines and related equipment such as compressors, storage facilities and facilities for liquefied hydrogen) and power-to-gas facilities above a certain threshold with cross-border relevance (i.e. aiming to supply at least two Member States*)" [98]. Hydrogen networks will also be appropriately reflected in the EU-wide Ten-year Network Development Plans (TYNDPs) prepared by the European Network of Transmission System Operators for Gas (ENTSOG). The projects of common interest (PCIs) are selected from the most recent TYNDP via a separate process led by the European Commission, hence these revisions to the TEN-E will open up further potential funding sources for cross-border hydrogen infrastructure projects. In this respect and with a view on the next TYNDP 2022, ENTSOG confirms that their model "is fit for hybrid network assessment where both methane and hydrogen coexist, according to the three pathways identified in the ENTSOG Roadmap (methane, blending and hydrogen), and that the relevant projects can be assessed" [102]. Furthermore, cross-border pipelines are already envisaged by transmission system operator's visions (see Section 6.4), but the necessary regulatory provisions are still lacking.

To conclude, cross-border hydrogen transport by pipelines between the Netherlands and Germany is still burdened by substantial regulatory uncertainties that have to be resolved on EU and national levels in a coordinated manner.

Underground hydrogen storage

Hydrogen storage falls under generic underground gas storage regulatory frameworks at European level. There are no regulatory frameworks specifically for hydrogen.

Underground hydrogen storage in the Netherlands is not currently being pursued. The Dutch Mining Act ("Mijnbouwwet") outlines the requirements regarding the storage of substances in the undergrounds (if greater than 500 m in depth) but has no specific requirements and references regarding hydrogen. The use of subsurface reservoirs for gas storage and as temporary buffers for various gases is therefore possible within Dutch Law, including the storage of hydrogen. A study into large-scale energy storage in the Netherlands has recently been conducted by TNO, which highlighted that the permit process for such projects is currently complex and long [103. The study concluded that more experience in such projects will help allow for the development of a more effective decision-making process. Underground gas storage has already been undertaken in the Netherlands, including natural gas storage in salt caverns in Zuidwending, natural gas storage in depleted gas fields in Norg, Grijpskerk, Bergermeer and Alkmaar, and nitrogen storage in salt caverns in Heiligerlee. It should be noted regarding aquifer storage specifically that, although technically possible, the current legal guidelines (in particular the Mining Act and Mining Regulation) have been highlighted as potentially prohibitive as they currently offer few possibilities relating to accommodating the necessary pressure increases [104].

In Germany, underground storage of hydrogen has been undertaken, for example, at the Ketzin site (aquifer storage) and the Kiel site (salt cavern storage), but in the form of town gas (62% hydrogen) [105]. Pure hydrogen storage in Germany has not yet reached commercial scales. Underground gas storage falls under the Federal Mining Act (BBergG) and is permitted under current regulation although hydrogen is not mentioned explicitly.

There are currently no regulatory barriers to storing hydrogen underground in Dutch and German national laws, but more explicit requirements are needed.

6.5.4. Conclusions and recommendations for a regulatory framework

Enabling hydrogen supply chains, as described and analysed in the study, would require various adjustments of regulatory frameworks both on EU and national levels. The proposed infrastructure configurations for hydrogen production along the North Sea of the Netherlands and Germany are only possible if rapid and massive scale-up of offshore wind capacities is coupled with onshore and offshore deployment of power-to-gas technology. The major regulatory gaps and uncertainties currently include the legal status of power-to-gas facilities as part of wider sector-coupling concepts. Regarding hydrogen production, the barrier for large-scale electrolysis deployment in Germany is due to a surcharge obligation on the electricity used, but this is being tackled and legal adjustments are ongoing. Furthermore, rules for legal definition and certification of green hydrogen in both countries need to be established and enforced, which is expected to be addressed on EU level in the short term. To allow system-wide optimisation the EU framework will need to address an issue of electrolysers locations (e.g. through targets, priority areas or incentive schemes) to ensure that they are planned and built at sites where large potentials of renewable energies and storage capacities are available. The regulatory framework for the offshore wind market in both countries is established, but the role of large-scale onshore and offshore hydrogen production from offshore wind is yet to be considered and developed. In Germany, a pilot area for “other energy generation” is planned and will provide an opportunity for initial deployment of an offshore hydrogen production and could serve as a valuable lesson. Regarding the transport and storage of hydrogen (via pipelines and in geological formations), it should be noted that although there are no regulations in place that are preventative, substantial gaps and uncertainties exist in current regulations. In this respect, an ongoing process of developing an enabling regulatory framework at EU level will steer further development, but interim measures are needed to allow timely preparation and planning of national and cross-border hydrogen backbone realisation. An initial proposal of such measures has been published in Germany. In any case, close cross-border cooperation is desired, to meet the needs for transnational transport and storage of hydrogen.

The main messages and recommendations regarding the regulatory framework are as follows:

1. **The rapid and massive scale-up of offshore wind-to-green hydrogen production capacities in the Netherlands and Germany will only be possible with further development and specification of the enabling rules. In particular, developments are required to allow for:**
   - The spatial planning of large-scale offshore power-to-gas deployment, including necessary connection of infrastructure in both countries (already in progress in Germany)
   - The tendering and market design for offshore wind energy and hydrogen production in both countries
   - The legal classification, development and management regulation of power-to-gas facilities in both countries
   - The avoidance of distortive taxes and levies by finalisation and implementation of announced measures in Germany
   - A legal definition and certification of green and other types of low-carbon hydrogen (e.g. via guarantees-of-origin certificates) in both countries
   - Cross-border offshore projects, including offshore hydrogen projects (e.g. through realisation of the North Sea Energy Cooperation)

2. **Establishing a transnational cross-border hydrogen market between the Netherland and Germany (including the North Rhine-Westphalia region) via hydrogen pipelines and storage infrastructure, mainly from repurposed gas infrastructure, is facing regulatory uncertainties that need to be tackled. In particular, the areas that need increased regulatory clarity include:**
   - Safe hydrogen transport via pipeline, by reconsidering the current classification of hydrogen as a chemical in the Netherlands
   - The regulatory framework for the development, management and access to repurposed and new hydrogen pipelines and storages. Since the EU rules are envisaged in the short to medium-term, transitional measures on national level (already proposed in Germany) are necessary for a timely planning and realisation of the hydrogen backbone
   - Coordinated cross-border planning and development of the future hydrogen pipelines and storages in view of TEN-E proposals, TYNDP for gas, and the national network planning processes

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Glossary

Term/abbreviation	Definition, description or specification
ACER	EU Agency for the Cooperation of Energy Regulators
AIB	The Association of Issuing Bodies
BBergG	The Federal Mining Act of Germany
BEV	Battery electric vehicles
BNetzA	The Federal Network Agency of Germany
BSH	The Federal Maritime and Hydrographic Agency of Germany
CAPEX	Capital expenditure (investment costs)
CCS	Carbon capture and storage
CEER	Council of European Energy Regulators
CERRE	Centre on Regulation in Europe
COM	European Commission
COSMO-REA6	Regional reanalysis tool from the Germany's National Meteorological Service, the Deutscher Wetterdienst (DWD)
CO_2	Carbon dioxide
DE	ISO country code for the Federal Republic of Germany
dena	Deutsche Energie-Agentur - German Energy Agency
DRI	Direct reduction of iron
DRI-H_2	Direct reduction of iron via hydrogen
DSO	Distribution network operators
EECS	European Energy Certificate System
EEG	German Renewable Energy Law
EEZ	North Sea Exclusive economic zones
FIEE	Fraunhofer Institute for Energy Economics and Energy System Technology
ENTSO-G	European Network of Transmission System Operators for Gas
EU	European Union

FCB	Fuel-cell buses
FCEV	Fuel-cell electric vehicles
FNB Gas	Vereinigung der Fernleitungsnetzbetreiber Gas e. V. – Association of Transmission System Operators Gas e.V.
FZ Jülich	Forschungszentrum Jülich
GHG	Greenhouse gas
GIS	Geographical information system
GOs	Established system of guarantees-of-origin
H2	Hydrogen
HDV	Heavy-duty vehicle with a gross load above 3.5 metric tons
HRS	Hydrogen refuelling stations
Hy3	The trilateral project "Hy3 – Large-scale Hydrogen Production from Offshore Wind to Decarbonise the Dutch and German Industry between the Netherlands, the Federal Republic of Germany, and the German Federal State of North Rhine-Westphalia (NRW)"
HVDC	A high-voltage, direct current (HVDC) electric power transmission system
H_2O	Water
INES	Initiative Erdgasspeicher e.V.
IEA	International Energy Agency
LBEG	State Authority for Mining, Energy and Geology (Landesamt für Bergbau, Energie und Geologie)
LCA	Life cycle assessment/analysis
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LCOT	Levelised transport costs (incl. storage costs)
LCOS	Levelised cost of storage
LDV	Light-duty vehicle with a gross load under 3.5 metric tons
LHV	Lower heating value (e. g. of hydrogen)
LNG	Liquefied natural gas

MENA region	Middle East and North Africa
NGR	Natural gas reformation
NL	ISO country code for the Kingdom of the Netherlands
NLOG	Dutch Oil and Gas portal This website provides information on energy and mineral resources in the deep subsurface of the Netherlands and Dutch continental shelf. This includes among others the exploration and production of natural gas, oil and geothermal energy.
NRW	German Federal State of North Rhine-Westphalia
NSE	North Sea Energy
OES	Other energy generation sectors
OPEX	Operating expenditures (operating costs)
OWF	Offshore wind farm
O_2	Oxygen
PCIs	Projects of common interest
PEM	Polymer electrolyte membrane
PEMFC	Polymer electrolyte fuel cell
PtL	Power-to-liquids
P2X	Power-to-X
RED II	European Commission's revised Renewable Energy Directive
RVO	The Netherlands Enterprise Agency
SMR	Steam methane reforming
TEN-E	The Trans-European Energy Networks Regulation
TNO	Netherlands Organisation for Applied Scientific Research
TRL	Technology readiness level
TSO	Transmission system operators
TYNDPs	The Union-wide Ten-year Network Development Plans
WTG	Wind turbine generator
WACC	Weighted average cost of capital

A. Appendix: Demand scenarios

A1 Description of methodology

The energy system model FINE-NESTOR (National Energy System Model with Sector Coupling) is the model applied to derive the scenario for hydrogen demand. The model maps the national energy supply from primary energy supply to the conversion sector, through to the end-use sectors. The sectors are represented in the form of technologies or process chains and linked via energy flows. The technologies are characterised in terms of energy, emissions and costs. The model is designed as a closed optimisation model with the objective function of the minimisation of total system costs. Investment decisions to reach a cost-efficient transition are modelled from the macroeconomic and not from the microeconomic perspective. Therefore, the results do not reflect the decisions of individual market participants, but rather show an idealised picture where all costs in the system are internalised during the decision-making process. Furthermore, the results are subject to uncertainties related to technology development in the future, as projections for technology-related and economic parameters, such as investment costs and efficiencies, were applied in the assessment. Since the model represents only part of the national economy, it is a partial equilibrium model. Given a CO_2 mitigation path, the FINE-NESTOR model can be used to calculate the cost-optimal transformation strategy for the entire energy system required to reach the CO_2 emissions reduction targets.

In order to be able to represent the fluctuating feed-in of renewable energy and its effects in a problem-oriented manner, the model has a temporal resolution in the hourly range. Particularly against the background of the increasing importance of sector coupling, a special advantage of the model approach is that all interactions of the energy system can be consistently taken into account. The model also uses a methodological approach that allows for cost uncertainties to be adequately addressed (see Lopion et al. [21]). Drivers of the model are energy consumption-determining demands (e.g. population development, gross value added, goods demands, transport demands, etc.), which are exogenously specified and are not part of the optimisation. The model is based on a myopic approach, i.e. on an approach that successively minimises the respective costs for the respective time intervals. To determine the transformation strategy, a back-casting method is used in a first step. It is based on the concept of first optimising the energy system of the target year as freely as possible and, based on the result, defining upper and lower limits for the systems of the intermediate time intervals. Then, in a second step, the cost optimisation of the preceding intervals is carried out, analogously to a forecasting approach, within the set limit values.

B. Appendix: Production scenarios

B1 Wind potential assessment

Methodology and assumptions for offshore WT

Existing wind turbines and assumptions on technological development of wind turbine generators (WTGs) are used as input data for a physical model when modelling generation time series. WTG technology parameters[41] are taken into account and their expected development is shown in Figure 49.

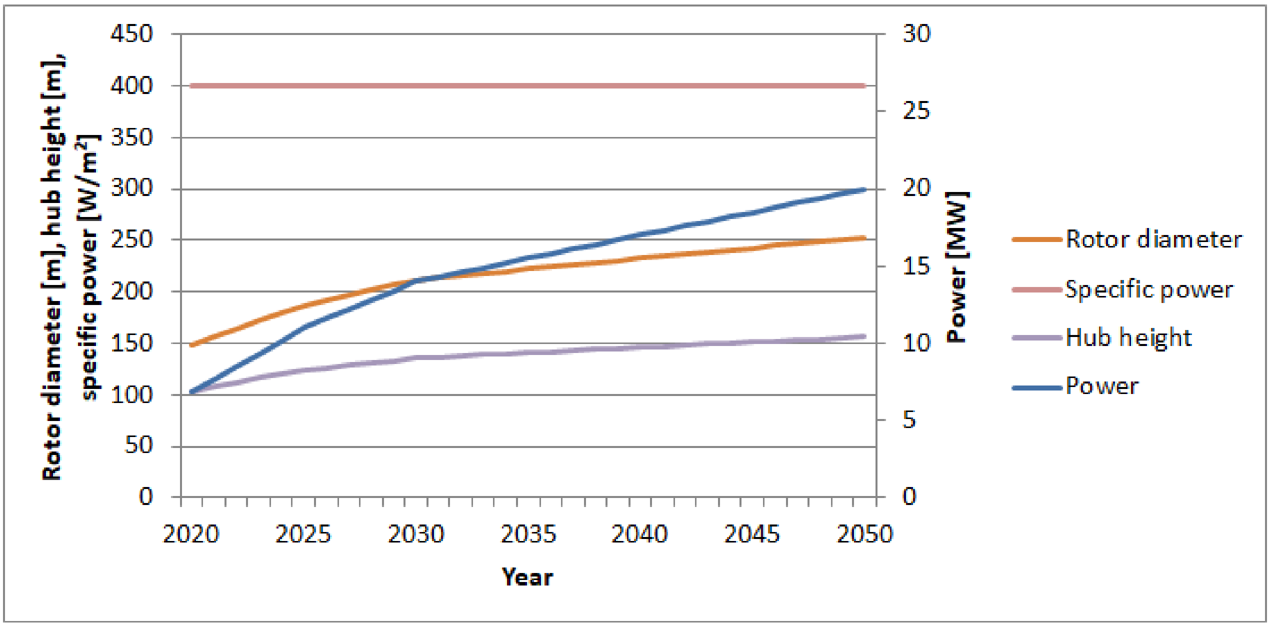


Figure 49: Technology assumptions for the modelling of the performance time series of wind turbines (own analysis)

Approach and assumptions of the analysis

- Nominal power: It is assumed that the average nominal output of the turbines will increase to 20 MW by 2050. The increase in nominal power is mainly driven by improved cost efficiency of large turbines. The third interim report on the area development plan assumes a nominal capacity of 15 MW by 2030 [32].
- Specific rated power: The specific rated output – i.e. the generator output per m^2 of rotor area – is on average approx. 370 W/m^2 for the offshore wind turbines built in the first half of 2020. According to industry surveys, only minor changes in the range between 350 and 400 W/m^2 are expected in the medium to long term [32]. Furthermore, the area development plan [26] assumes 400 W/m^2. Therefore, this value is taken into account in the modelling and assumed to be constant over time. A lower specific rated output leads on the one hand to higher space requirements and higher specific investment costs of the WTGs, but on

[41] Parameters represent the average values of the WTGs built in the respective year. The maximum values as a reflection of the state of the art would be more extreme.

the other hand also to higher capacity utilisation and thus higher energy yields in relation to the installed capacity.

Rotor diameter: The development of the rotor diameter results mathematically from the assumptions regarding the nominal power and the specific area output of the turbines. It is derived from the assumptions described above.

- Hub heights: Due to the low surface roughness of the water surface and the resulting steep wind profile, higher hub height results in a comparatively small increase in yield compared to WTGs on land, so that for economic reasons the tower height is limited to what is required for the rotors. However, an increase in hub height can be expected as a consequence of the increase in rotor diameter. In order to ensure a constant distance of the rotor blade tip to the water surface of approx. 30 m, the hub height must increase with increasing nominal power (while maintaining the same specific power rating). The development of the hub height is therefore derived mathematically from the assumptions of the nominal power and the specific area output, analogous to the development of the rotor diameter.

Assumptions for installation density

- When determining the installable capacity on a given area, a distinction is made between a nominal and a corrected power density [26]. The nominal power density results from the installed capacity and the size of the enveloping areas. For the determination of the corrected power density, a buffering or enlargement of the individual areas has to be carried out in the first step. This expansion of the area should reflect the required (half) minimum distance between two WTGs. With a minimum distance of five rotor diameters between individual WTGs, the wind farm area would have to be buffered with 2.5 rotor diameters. The quotient of the nominal power of a wind farm and the corrected (buffered) area results in the corrected power density. This value is a more comparable parameter, since distortions due to the size and shape of the individual areas are not as significant with this method. In the study, a buffer of 2.8 rotor diameters was applied while assuming an average rotor diameter of 220 m resulting in a buffer size of 616 m.
- Corrected power density of 8 to 10 MW/km^2 was applied for the German North Sea, depending on the location as described in [26]. For zone 1 and zone 2, a higher corrected power density of 9.5 to 10 MW/km^2 is assumed, while offshore wind farms in zones 3 to 5 are modelled with a corrected power density of 8 MW/km^2. This lower power density is justified on the one hand by larger connected areas and on the other hand by restrictions due to grid connection.
- Power density of existing wind farms in the Netherlands is currently rather low, which may partly be due to their location in the English Channel with a less advantageous wind resource. Furthermore, space for offshore WTGs in relation to domestic electricity demand is less limited in the Netherlands, allowing a lower power density for WTG installations. For the given reasons, a corrected power density of 6.0 MW/km^2 was applied. Similar assumptions were made in PBL Netherlands Environmental Assessment Agency (2018) [28]. The corrected value of 6.0 MW/km^2 corresponds to an average nominal power density of 6.9 MW/km^2.

Assumptions for wind farm shading (wake losses)

- A wind turbine extracts energy from moving air masses. This energy is restored by vertical energy transport from the above air layers. However, due to low turbulences in the wind field above the sea, this restoration happens rather slowly in comparison to typical onshore situations. Therefore, wake effects in offshore wind farms are more pronounced in comparison to onshore wind farms and greater distances between wind turbines are required.
- The wind farm shading is taken into account by using an empirically derived, wind speed dependent shading curve. Results from different research groups (i.e. Fraunhofer IWES modelling of wake losses for the FEP scenario within the X-Wakes research project) on the reassessment of the offshore wind potential in the German North Sea provides guidance but a realistic estimation of the yield reduction due to cross-farm shading effects in the case of a large-scale expansion of offshore wind energy in the North Sea region is yet to be carried out.

Assumptions for area availability in the German North Sea

- The reserved and priority areas provided by the Federal Maritime and Hydrographic Agency (BSH) in the draft of the spatial development plan as of 19 Sept. 2020 [27]: This scenario accounts for the political targets of the German government aiming for 20 GW offshore capacity in 2020 and 40 GW in 2040. As suitable areas in the Baltic Sea are very limited, most of the development will happen in the German North Sea.
- "Sonstige Energiegewinnungsbereiche Nordsee" (SEN) areas: These areas were declared specified areas for non-grid connected energy generation in the draft of the spatial development plan [26].
- Additional areas in the shipping lane SN10: However, these areas are assumed to be built last, as it is quite uncertain whether these areas will become available.
- All other areas will be repowered after 25 years, resulting in the installation of more modern WTGs. Exceptionally, repowering of wind farms in areas with high populations of harbour porpoises and loons will not be possible.42
- The German North Sea EEZ covers approx. 28,521 km² [31]. Of this area, 6,123 km² have been identified for the construction of offshore wind farms. However, 267 km² of currently identified areas are located in protected zones (no repowering – see above). Another 10 km² are located in existing areas within the 12 nautical mile zone, which are also not considered for repowering. Further 1,253 km² of areas for offshore use are within the shipping lane SN10 and are not part of the latest draft of the spatial development plan [27] but were identified as possible areas for offshore use in the conception B of the preliminary draft of the area development plan [26]. Correspondingly, 4,593 km² are with high probability available for the installation of offshore wind turbines.

[42] Wind turbines in these farms will be decommissioned at the end of their lifetime, which is assumed to be 25 years after deployment.

Original and smoothed (normalised) power curve

A smoothed power curve is generated by means of Gaussian smoothing, which better reflects the operating behaviour of a wind farm, taking into account the spatially and temporally averaged wind speed data rather than the direct use of the power curve.

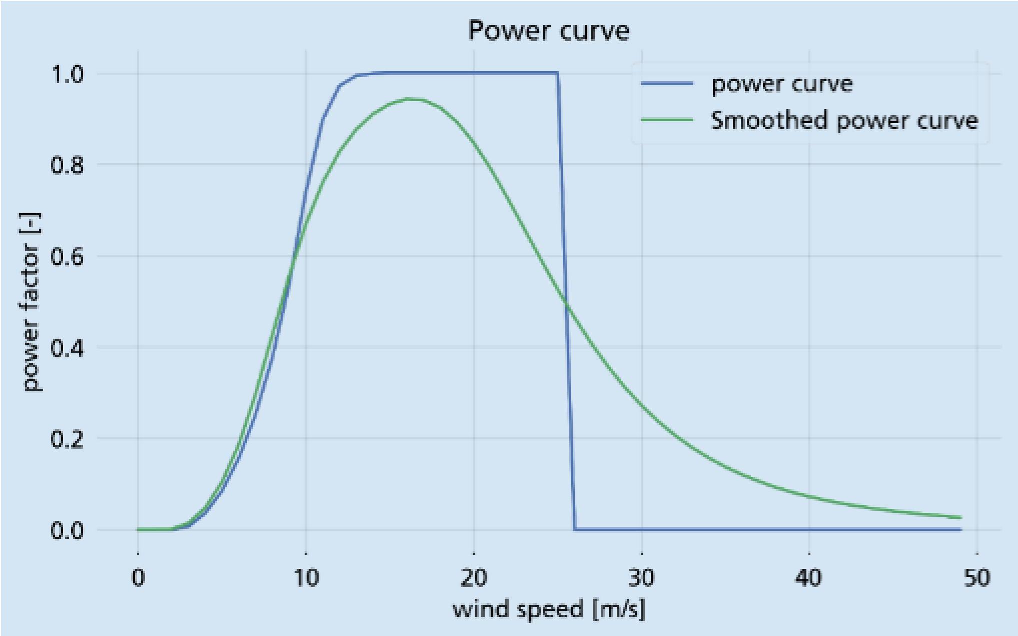


Figure 50: Original and smoothed (normalised) power curve with a shutdown speed of 25 m/s [own representation]

Installed capacity of offshore wind farms, energy yield, average capacity factor and average full-load hours in the considered years

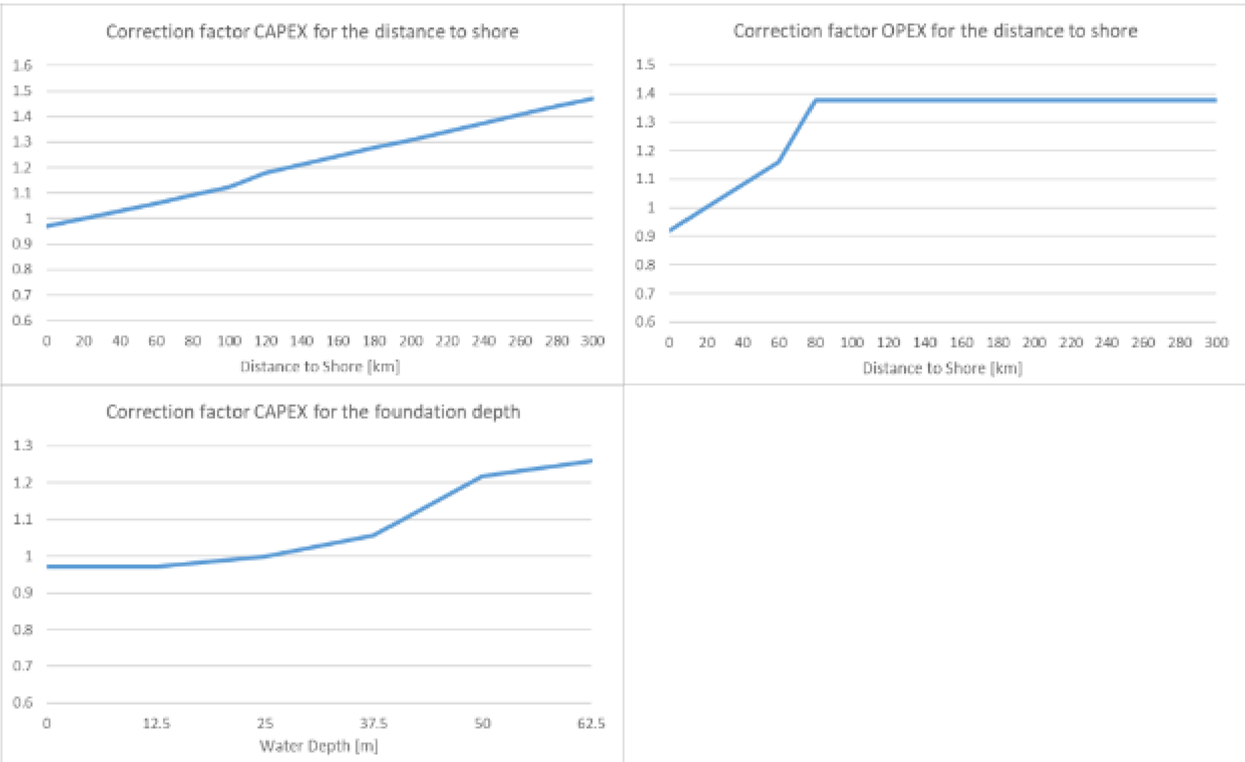
Table 8: Incremental total installed offshore wind capacity (GW), energy yield (TWh), average capacity (%) and average full-load hours (h) for the German and Dutch EEZ in the North Sea from 2025 to 2050

	Installed capacity (GW)	Energy yield (TWh)	Average capacity factor	Average full-load hours
German North Sea				
2025	9.7	38.7	45.33	3,982
2030	19.4	76.8	44.96	3,950
2035	29.4	115.1	43.94	3,860
2040	37.9	144.3	43.3	3,803
2045	48.3	180.8	42.61	3,743
2050	53.4	195.5	41.69	3,662
Dutch North Sea				
2025	5.3	19.2	41.15	3,614
2030	11.6	437	42.53	3,736
2035	26.2	97.3	42.25	3,711
2040	40.3	151	42.66	3,747
2045	54.4	202	42.26	3,712
2050	67.9	249	41.75	3,668

LCOE model

A cost model is applied to evaluate the development sequence of yet unscheduled wind farms. The cost model calculates the levelised cost of electricity (LCOE) as a function of yield, water depth and distance from shore. The investment costs (CAPEX) are derived from two similar cost models [106, 107], which are adapted to the specific water depth. The operating costs (OPEX) are determined similarly, but they only depend on the distance to the coast. For calculating LCOE, energy yield is modelled based on a standard WTGs and the meteorological year 2012. The areas are then selected starting from the lowest LCOE until the desired capacity is reached [34].

The calculation of CAPEX and OPEX for offshore wind turbines is based on Härtel et al. 2018. The correction factors taking into account the water depth and the distance to the shore as well as the installation year have been calculated as follows.[43]



[43] The correction factor for CAPEX and OPEX for the year of construction was changed from the former reference year 2014 to the new reference year 2020.

- The correction factor for CAPEX and OPEX for the year of construction was changed from the former reference year 2014 to the new reference year 2020.
- The CAPEX per kW depending on the distance to shore (see figures above) and depending on the foundation depth (see figures above) have been transformed into correction factors. The referenced distance to the shore is 20 km, and the referenced foundation depth is 20 m (correction factor for distance to the shore (20 km) = 1, correction factor for water depth (20 m) = 1).
- The values for OPEX per kW depending on the distance to shore (see figures above) were also recalculated using a correction factor referencing to 20 km distance to shore (correction factor for distance to the shore (20 km) = 1).
- Correction factors for CAPEX and OPEX for the distance to shore and the foundation depth were calculated for each wind farm.
- The CAPEX for a wind farm is determined by multiplying the capacity built in year X with the reference value for CAPEX per installed kilowatt (2,000 EUR/kW) and the correction factors for distance to shore, foundation depth and year of construction for the same reference year X.
- The average CAPEX of a cluster/zone is weighted proportionally to the cluster's/zone's overall installation volume in the reference year.
- The OPEX of a wind farm is calculated by multiplying the capacity built in year X with the reference value for OPEX per installed kilowatt (€65/kW*a), the correction factor for the distance to shore and the correction factor for the year of construction for the same reference year X.
- The average OPEX of a cluster/zone is weighted proportionally to the cluster's/zone's overall installation volume in the reference year.

The LCOE calculation is based on the annuity method described in (Verein deutscher Ingenieure VDI 2012a) and (Verein deutscher Ingenieure VDI 2012b). The table below shows which annuities have been included as cost components in the calculation of the LCOE model for the different scenarios.

Scenario A1 and A2	Scenario B1	Scenario B2
▪ Wind farm ▪ Platforms for the offshore converters ▪ Offshore converters ▪ Cables and onshore converters	▪ Wind farm ▪ Cables for connecting the wind farm to the offshore electrolysis platform	▪ Wind farm ▪ Platforms for the converters* ▪ Offshore converters* ▪ Cables* *only for the additional power connection to the shore

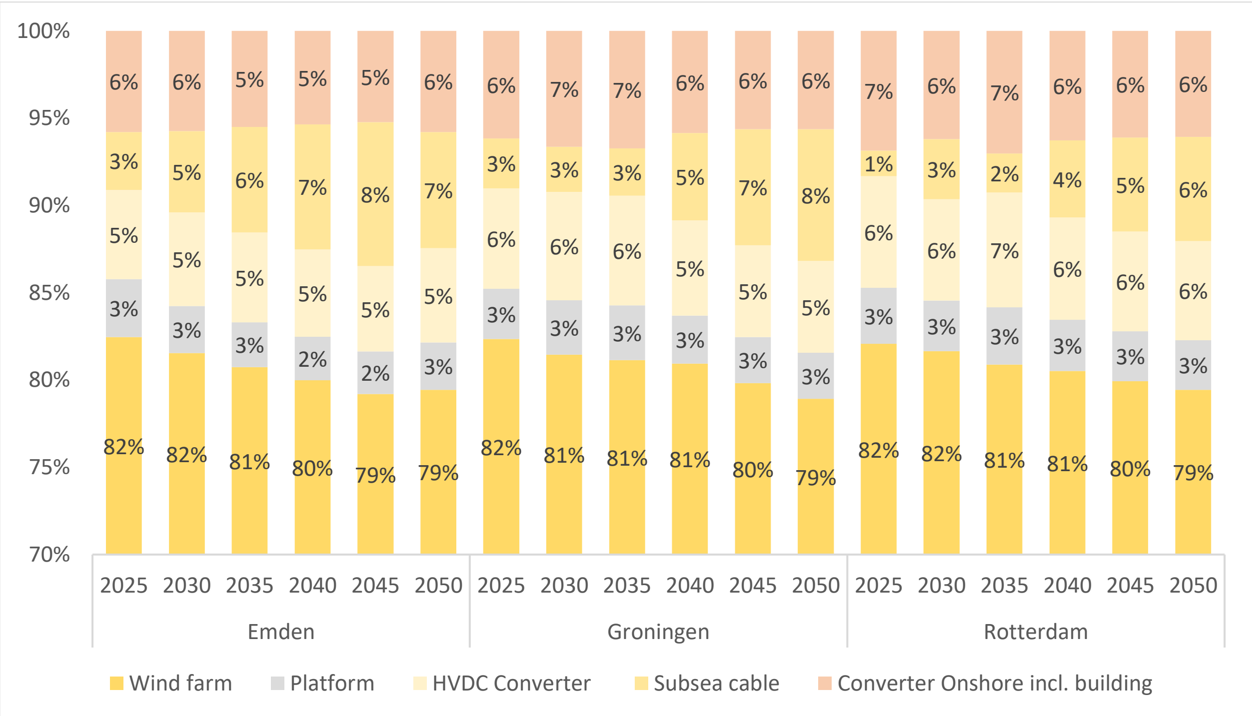
The annuities are then divided by the produced electricity. For this the following equation was used:

$$LCOE = \frac{annuity\ of\ CAPEX + annuity\ of\ OPEX}{capacity\ of\ wind\ farm * FLH\ of\ wind\ farm}$$

Assumed values for the calculation of the LCOE in the German North Sea:

German North Sea	CAPEX wind farm [€/kW]	OPEX wind farm [€/kW*a]	LCOE [€/MWh]
2025	2,300	78	77.7
2030	0	0	
2035	2,660	75	82.6
2040	2,612	72	87.3
2045	2,731	69	89.9
2050	2,365	65	84.1

An overview of the composition of the LCOE cost components can be seen in the diagram below.



Levelised cost of electricity (LCOE) for all reference years, feed-in points and scenarios.

LCOE [€/MWh]	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
DE A1 Emden	73.34	77.76	83.20	86.78	90.27	83.26
DE A2 Emden	73.34	77.76	83.20	86.78	90.27	83.26
DE B1 Emden	64.45		69.74	69.40	72.59	66.24
DE B2 Emden	64.45		73.20	73.15	74.26	66.24
DE SEN-1 Emden	64.45					
NL A1 Groningen	79.26	71.13	70.75	80.43	84.43	85.41
NL A2 Groningen	79.26	71.13	70.75	80.43	84.43	85.41

NL B1 Groningen				62.36	64.42	65.01
NL B2 Groningen				67.48	65.55	66.15
NL A1 Rotterdam	71.29	76.18	67.63	75.09	77.80	79.28
NL A2 Rotterdam	71.29	76.18	67.63	75.09	77.80	79.28
NL B1 Rotterdam				62.99	64.76	66.27
NL B2 Rotterdam				67.77	64.76	66.27

B2 Hydrogen production potential assessment

Methodology and assumptions for hydrogen production scenarios

Scenario	Assumptions and methodology
A1	▪ Only power that cannot be integrated into the grid is used for electrolysis. This leads to the smallest full-load hours of all scenarios. ▪ Full-load hours of the electrolyser in Germany vary between 890 and 2,456 hours, depending on the assumed grid capacity in each reference year. The full-load hours of the electrolyser vary between 1,876 and 2,478 h, depending on the assumed grid capacity in each reference year. The duration curves are presented in Section 3.3 for each reference year.
A2	▪ A fixed ratio of the generated energy is fed into the electrolysis process, based on an economic optimisation (ratio of the electrolyser capacity to the maximum wind production is calculated for every reference year). This leads to a lower electrolyser capacity (than A1) and thus to an increase in full-load hours. ▪ Hydrogen production follows electricity generation. To achieve this, it is necessary to assume both grid expansion and electrolyser development. The duration curves are presented in Figure 51–Figure 54 for each reference year. The resulting electrolyser deployment roadmap is described in Section 4.3.1
B1	▪ All the electricity generated from the wind farms in zones 4 & 5 of the German EEZ and clusters 3, 4 & 5 in the Dutch EEZ is directly fed into the electrolyser. In case of Netherlands, Groningen is the hydrogen feed-in point for clusters 4 & 5 and Rotterdam is the hydrogen feed-in point for cluster 3. ▪ Offshore electrolyser is designed for 95% of the maximum wind production. Surplus energy is curtailed, but that is only about 1–2% of the total energy depending on the respective cluster or zones. ▪ Pilot zone SEN-1 (Germany) is part of EN 8 in zone 3, but it is planned to use this area as a pilot area for offshore hydrogen production and therefore to install an offshore electrolyser in this area.
B2	▪ Deployment of electrolyser capacity for scenario B2 is based on similar assumptions as in scenario B1. In contrast to scenario B1, additional electricity grid connections of 2 GW per zone or cluster are installed for technical reasons (for grid stability and support). The electrolyser capacity is calculated by reducing the maximum power output of the considered wind farms by the installed grid capacity.

Distance per concept and reference year (cables to the shore; pipelines to the feed-in-points)

Distance [m]	2025	2030	3035	2040	2045	2050
DE A1 Emden	75	110	151	183	216	157
DE A2 Emden	75	110	151	183	216	157
DE B1 Emden		0	234	229	252	181
DE B2 Emden		0	234	229	252	181
DE SEN-1 Emden	133					
NL A1 Groningen	63	53	55	116	161	183
NL A2 Groningen	63	53	55	116	161	183
NL B1 Groningen	0	0	0	165	211	237
NL B2 Groningen	0	0	0	165	211	237
NL A1 Rotterdam	29	76	43	96	120	135

NL A2 Rotterdam	29	76	43	96	120	135
NL B1 Rotterdam	0	0	0	153	175	195
NL B2 Rotterdam	0	0	0	153	175	195

Duration curves for all sub-concepts

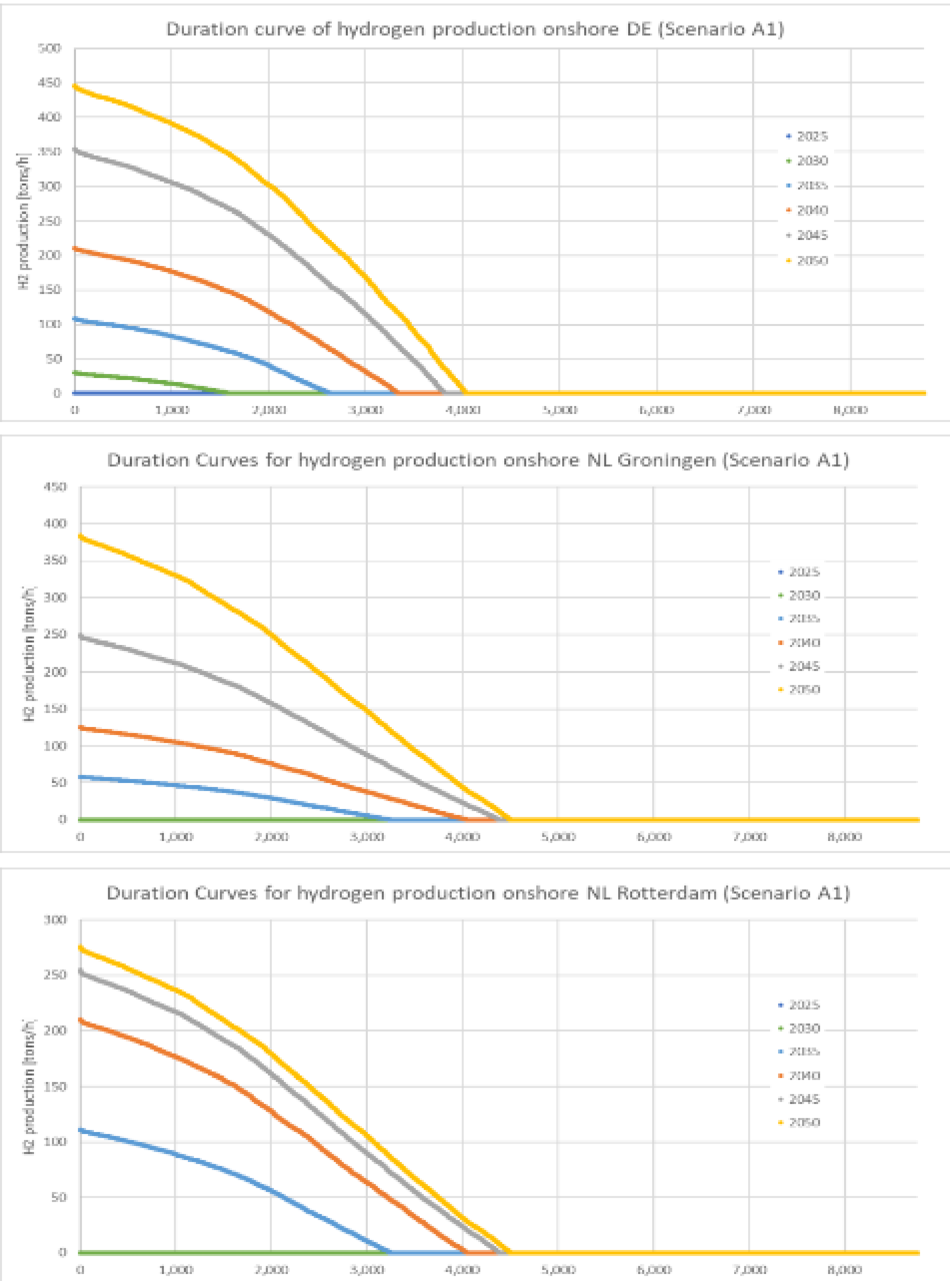


Figure 51: Duration curves for all reference years for scenario A1

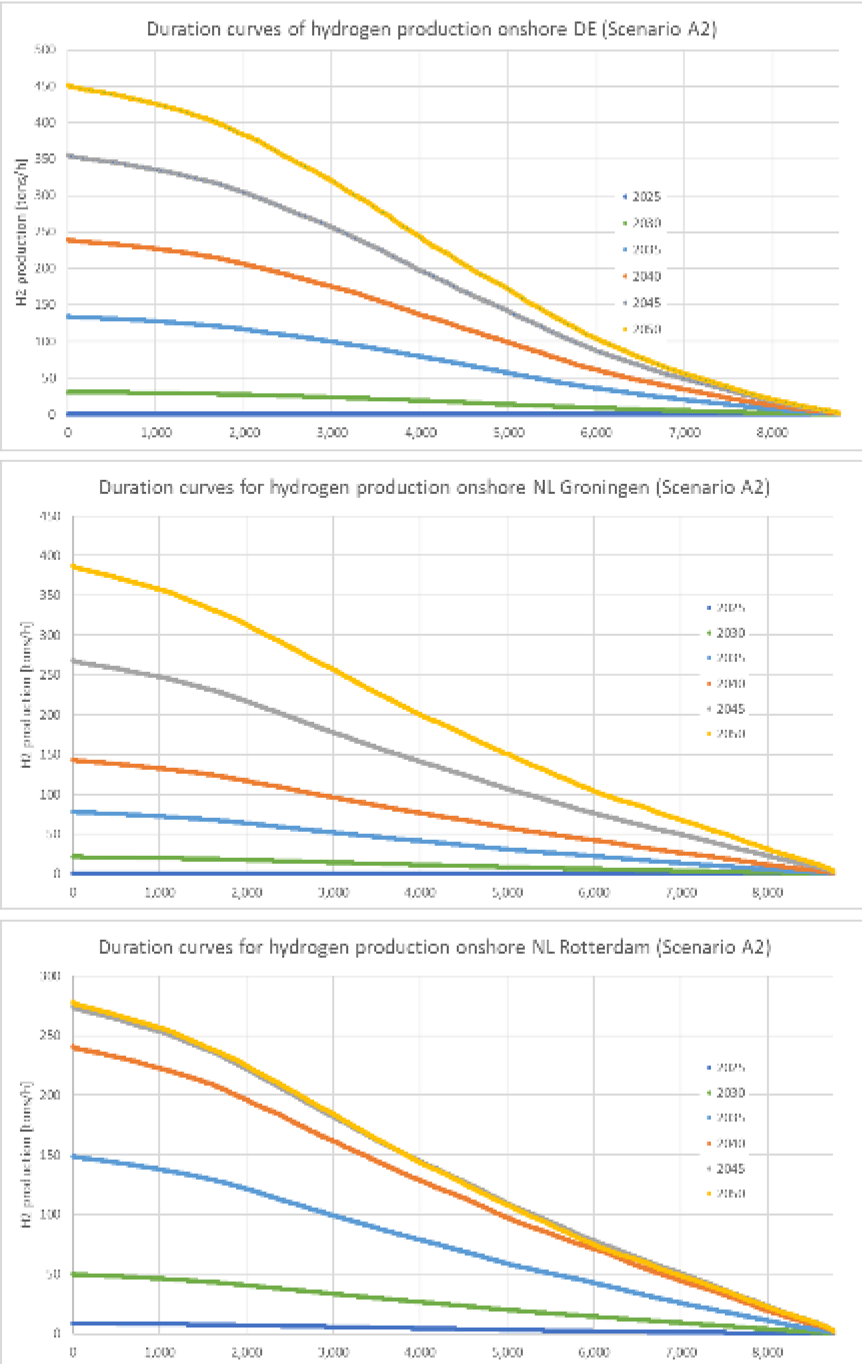


Figure 52: Duration curves for all reference years for scenario A2

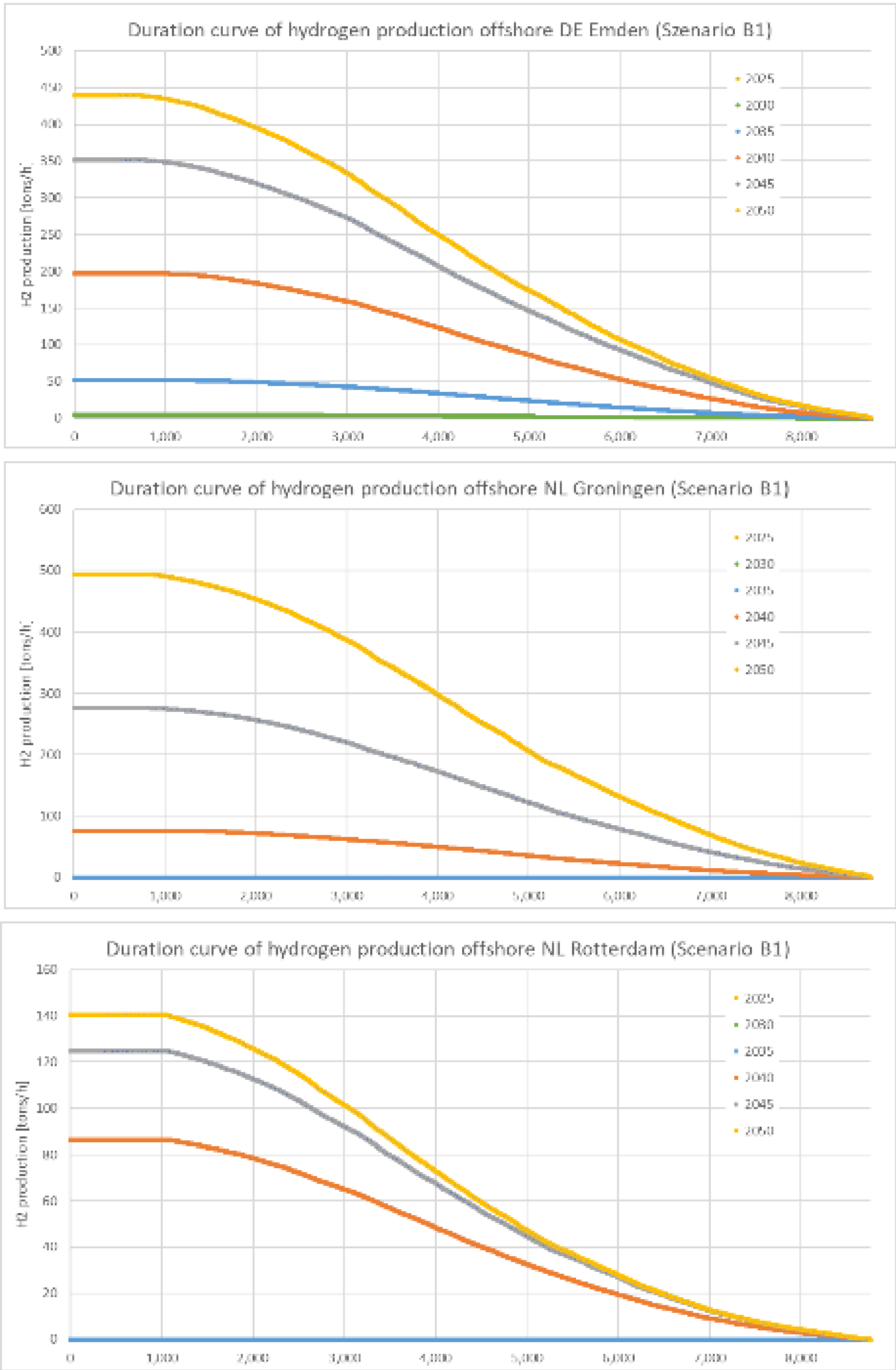


Figure 53: Duration curves for all reference years for scenario B1

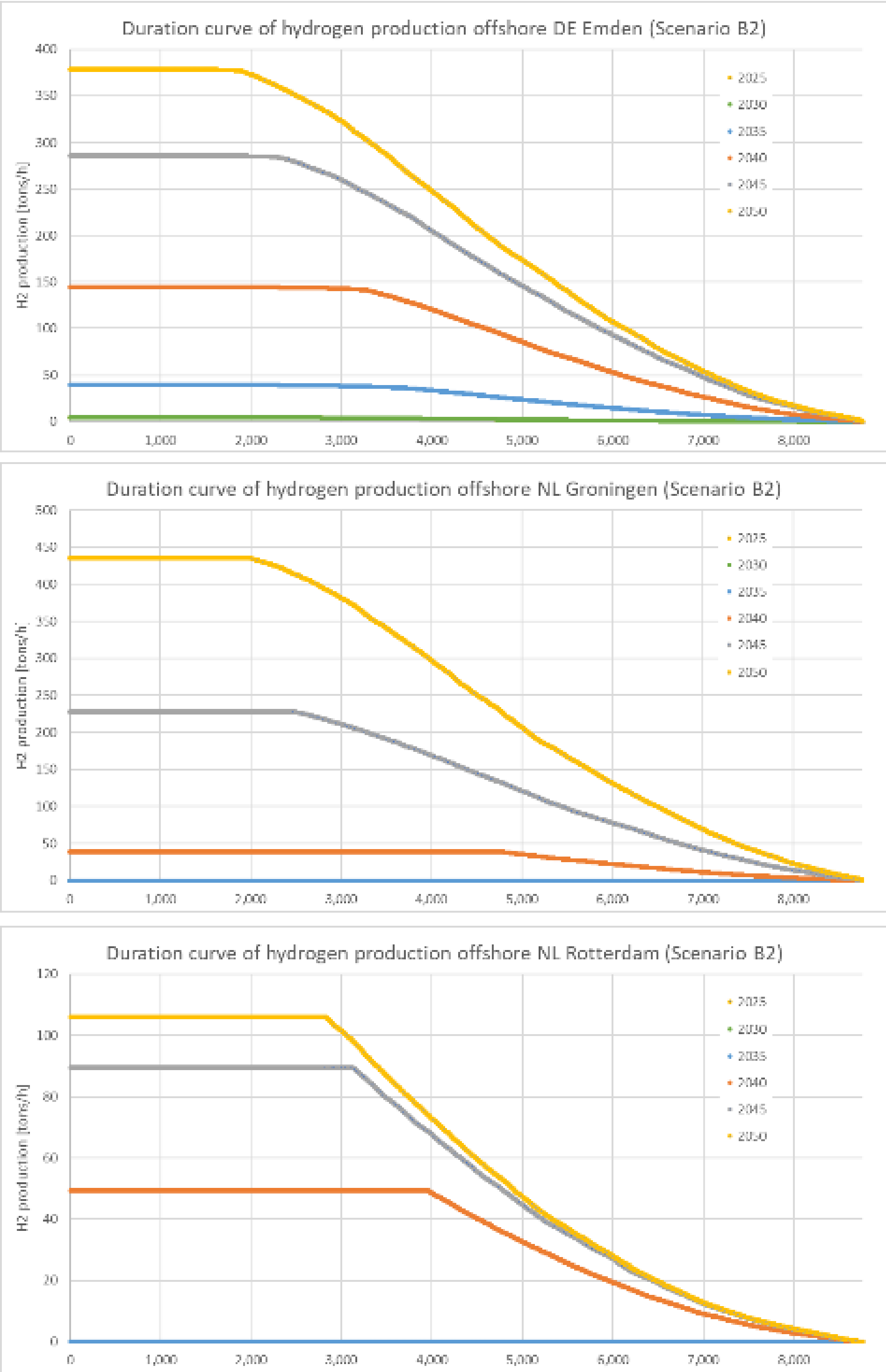


Figure 54: Duration curves for all reference years for scenario B2

Installed electrolysis capacity for all sub-scenarios for Germany and the Netherlands

Capacity [MW]	2025	2030	3035	2040	2045	2050
DE A1 Emden	0	1,477	5,276	10,137	16,924	21,222
DE A2 Emden	0	1,500	6,500	11,500	17,000	21,500
DE B1 Emden	248	248	2,527	9,488	16,835	20,942
DE B2 Emden	248	248	1,947	6,974	13,708	18,031
DE SEN-1 Emden	248	248	248	248	248	248
NL A1 Groningen	0	0	2,831	6,028	11,923	18,303
NL A2 Groningen	65	1,056	3,789	6,907	12,856	18,463
NL B1 Groningen	0	0	0	3,654	13,218	23,470
NL B2 Groningen	0	0	0	1,846	10,913	20,705
NL A1 Rotterdam	0	0	5,388	10,118	12,190	13,122
NL A2 Rotterdam	435	2,444	7,211	11,593	13,144	13,237
NL B1 Rotterdam	0	0	0	4,149	5,969	6,695
NL B2 Rotterdam	0	0	0	2,368	4,283	5,047

Hydrogen production quantities for all sub-scenarios for Germany and the Netherlands

H_2 prod. [t/y]	2025	2030	3035	2040	2045	2050
DE A1 Emden	0	26,880	172,678	426,978	823,732	1,095,356
DE A2 Emden	0	142,391	608,546	1,069,365	1,564,105	1,945,428
DE B1 Emden	24,107	24,107	251,555	934,570	1,625,820	1,986,476
DE B2 Emden	24,107	24,107	220,142	798,449	1,482,767	1,862,620
DE SEN-1 Emden	24,107	24,107	24,107	24,107	24,107	24,107
NL A1 Groningen	0	0	109,620	283,707	598,955	953,151
NL A2 Groningen	5,538	94,683	341,072	632,409	1,172,924	1,675,153
NL B1 Groningen	0	0	0	370,448	1,318,193	2,305,247
NL B2 Groningen	0	0	0	245,378	1,205,462	2,195,081
NL A1 Rotterdam	0	0	208,636	476,214	612,378	683,364
NL A2 Rotterdam	37,262	219,231	649,148	1,061,524	1,199,211	1,201,005
NL B1 Rotterdam	0	0	0	384,981	546,858	602,788
NL B2 Rotterdam	0	0	0	283,585	468,011	531,303

Electrolyser full-load hours for sub-concepts in Germany and the Netherlands

Full load hours [h/y]	2025	2030	3035	2040	2045	2050
DE A1 Emden	0	890	1,586	2,026	2,328	2,456
DE A2 Emden	0	4,641	4,536	4,473	4,400	4,306
DE B1 Emden	4,821	4,821	4,822	4,738	4,618	4,514
DE B2 Emden	4,821	4,821	5,477	5,507	5,173	4,915
DE SEN-1 Emden	4,821	4,821	4,821	4,821	4,821	4,821
NL A1 Groningen	0	0	1,876	2,264	2,402	2,478
NL A2 Groningen	4,240	4,385	4,361	4,404	4,363	4,317
NL B1 Groningen	0	0	0	4,877	4,769	4,674
NL B2 Groningen	0	0	0	6,394	5,282	5,045
NL A1 Rotterdam	0	0	1,876	2,264	2,402	2,478
NL A2 Rotterdam	4,240	4,385	4,361	4,404	4,363	4,317
NL B1 Rotterdam	0	0	0	4,463	4,381	4,284
NL B2 Rotterdam	0	0	0	5,761	5,225	5,009

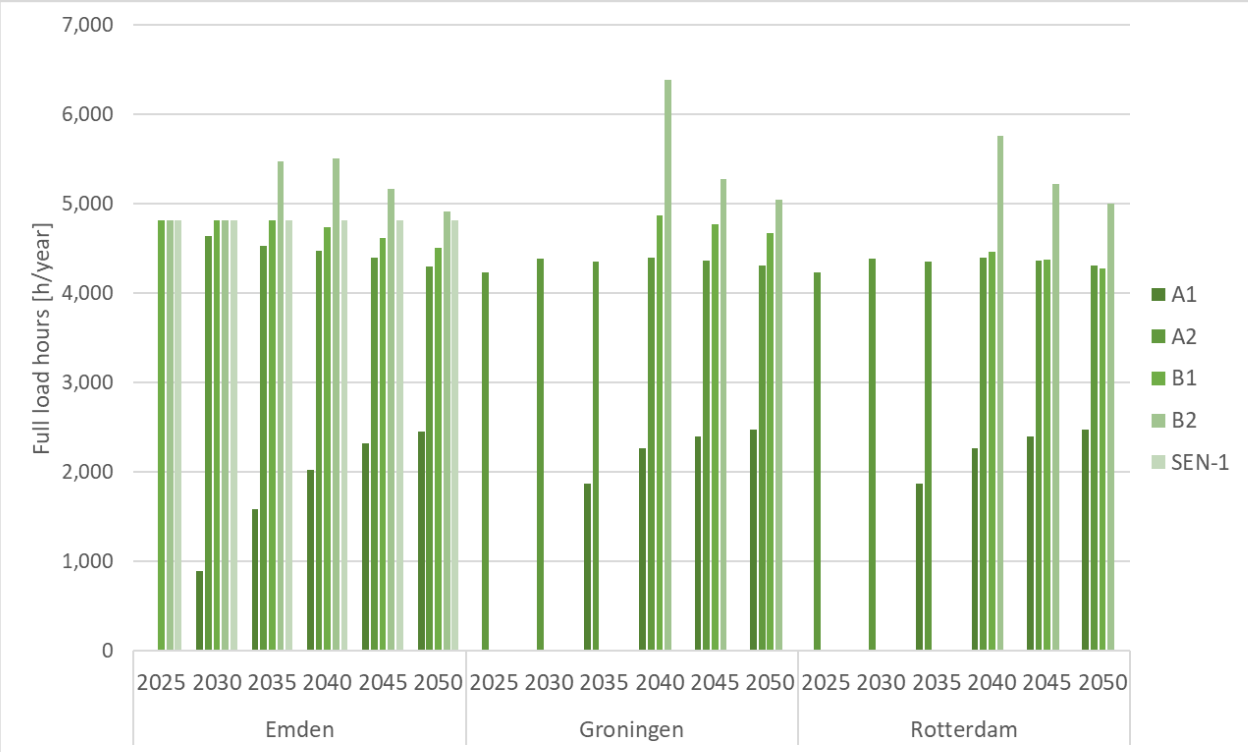


Figure 55: Electrolyser full-load hours for all scenarios in Germany and the Netherlands

Electricity shares for hydrogen production

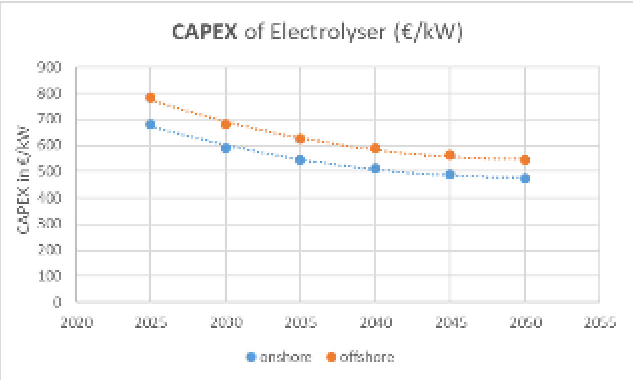
The electricity share is the part of the electricity that is consumed in the electrolysers for hydrogen production compared to the total amount of produced offshore wind electricity.

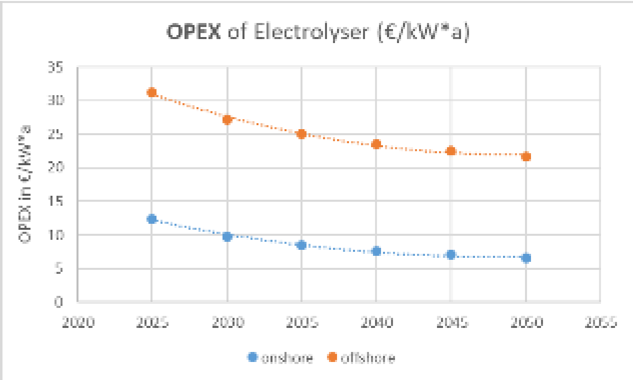
Electricity share for electrolysis	2025	2030	3035	2040	2045	2050
DE A1 Germany	0%	2%	7%	14%	22%	27%
DE A2 Germany	0%	9%	26%	36%	42%	48%
DE B1 Germany	0%	0%	10%	30%	43%	48%
DE B2 Germany	0%	0%	8%	26%	39%	45%
NL A1 Netherlands	0%	0%	16%	24%	29%	31%
NL A2 Netherlands	11%	35%	50%	54%	56%	55%
NL B1 Netherlands	0%	0%	0%	24%	45%	56%
NL B2 Netherlands	0%	0%	0%	17%	40%	52%

Assumptions for calculation of CAPEX and OPEX

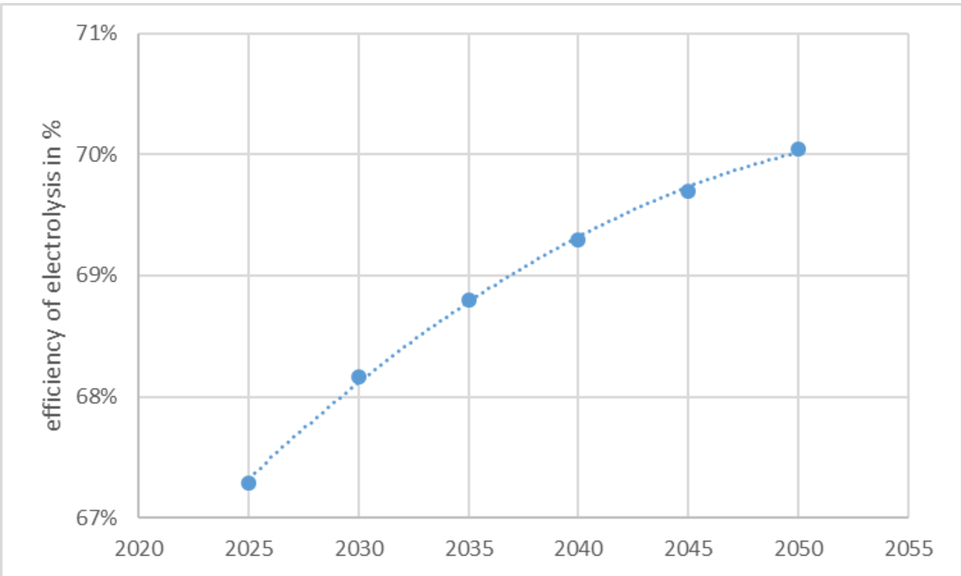
Fraunhofer IEE used a cost curve model to calculate the PEM electrolyser costs taking into account data from:

- International Energy Agency (IEA) 2019
- Smolinka et al. 2018
- Bertuccioli et al. 2014
- van ’t Noordende und Ripson 2020
- Bazzanella und Ausfelder 2017





The correction factors taking into account the water depth and the distance to the shore as well as the installation year have been calculated as follows:



Cost assumptions for hydrogen production cost assessment

The total CAPEX for the entire lifetime of 25 years, for example, has been calculated by adding together an initial hardware cost for the system including above mentioned components and a stack replacement[44] cost in accordance with the stack lifetime in equivalent full-load operating hours and taking into account the residual value equivalent to the remaining lifetime of the stack.

In this respect, redesign of the cooling system and other components was assumed by adding 5% of CAPEX as well as another 5% of CAPEX for extended service life of critical parts (i.e. filters, etc.) in order to minimise service requirements and maximise service intervals. Such modifications are necessary for a safe and reliable operation of offshore installations to increase their technical availability and reduce service requirements. For offshore electrolysis, an additional cost item for seawater desalination is used as a fixed amount[45] for all scales and years. Furthermore, an important additional cost item for the offshore electrolysis is the platform required for the installation of the electrolysis. Here, the cost model developed in (Dambeck et al. 2020b) has been used. The footprint of the platform is equal to $4m^2$/MW of electrolysis capacity, which means that a 40x60 m^2 platform provides space for 600 MW of electrolysis capacity. The total platform cost is calculated as a function of wind power.

The financing cost parameters for LCOE and LCOH are identical. The observation period (project time span) is 25 years, the interest rate amounts to 5% and the cost escalation rate is 1.455%, which is the average inflation rate of Germany taking into account the last 20 years (Statistische Bundesamt (Destatis) 2020).

Table 9: Cost assumption for scenario A1 & A2

Component	Cost assumption	Source
Wind farm	Costs vary depending on distance from the coast and water depth	IEE calculations
Platform for converter	100€/kW wind	(Dambeck et al. 2020b)
HVDC converter	€200 €/kW wind	(Dambeck et al. 2020b)
Cable	1.50 €/km*kW Wind	(Dambeck et al. 2020b)
Onshore converter	200 €/kW Wind	(Dambeck et al. 2020b)
Electrolyser	Costs vary depending on year of construction (learning curve) and onshore/offshore installation	IEE calculations

[44] Stack costs are set at 60% of the electrolyser hardware CAPEX. In this approach, an average efficiency is applied throughout the entire stack lifetime assuming a linear degradation.

[45] Based on Dambeck et al. 2020b, CAPEX for seawater desalination is 9 €/t*a

Table 10: Cost assumption for scenario B1 & B2

Component	Cost assumption	Source
Wind farm	Costs vary depending on distance from the coast and water depth	IEE calculations
Platform for electro-lyser	70 €/kW Wind	(Dambeck et al. 2020b)
Desalination	9 €/t H_20*a	(Dambeck et al. 2020b)
Electrolyser	Costs vary depending on year of construction (learning curve) and on-shore/offshore installation	IEE calculations
Compressor	3,000,000 €/MW compressor	(Dambeck et al. 2020b)
Pipeline	DN 250 1,353,333 €/km DN 500 1,753,333 €/km DN 1100 3,253,333 €/km	(Dambeck et al. 2020b)

The general formula used for the levelised cost of hydrogen (LCOH) is:

$$LCOH = \frac{LHV}{\eta_{tot}}\left(\left(\frac{i\cdot(1+i/100)^n}{(1+i/100)^n-1} + O\&M\right)\frac{CAPEX}{FLH} + LCOE\right)$$

LCOH	Levelised Cost of Hydrogen [€/kg]	Values
LHV	Lower heat value of hydrogen	33.3 kWh/kg
ηtot	Nominal system efficiency in % of LHV (e.g. 50 kWh/kg equals 66.7%)	depends on year of construction 49.5–47.6 MWh/t
i	Interest/discount rate (as in a fixed annuity approach)	5%[46]
O&M	Maintenance and operation cost, typically a fixed percentage p.a. of CAPEX	depends on the component
CAPEX	Annuity of the total specific investment cost of the electrolyser system including replacement costs [€]	depends on the component
FLH	Full-load hours [h]	depends on the scenario
LCOE	Levelised cost of electricity [€/kWh]	depends on scenario

Table 11: Hydrogen production costs for the sub-scenarios in Germany and Netherlands

LCOH [€/kg]	2025	2030	2035	2040	2045	2050
DE A1 Emden		€6.30	€5.26	€5.08	€5.08	€4.66
DE A2 Emden		€4.47	€4.63	€4.72	€4.82	€4.50
DE B1 Emden			€4.60	€4.43	€4.52	€4.07
DE B2 Emden			€4.68	€4.50	€4.51	€4.00
DE SEN-1 Emden	€5.16					
NL A1 Groningen			€4.62	€4.82	€4.89	€4.86
NL A2 Groningen	€4.75	€4.16	€4.03	€4.42	€4.54	€4.60
NL B1 Groningen				€4.11	€4.08	€4.06
NL B2 Groningen				€4.16	€4.04	€4.04
NL A1 Rotterdam			€4.47	€4.56	€4.58	€4.57
NL A2 Rotterdam	€4.36	€4.40	€3.88	€4.16	€4.23	€4.31
NL B1 Rotterdam				€4.17	€4.08	€4.18
NL B2 Rotterdam				€4.27	€3.95	€3.99

[46] The interest rate for the calculations is assumed to be 5%, taking into account numbers from Dambeck et al. 2020a, Kost et al. 2018, Schyska und Kies 2020, Steffen 2020 and Hobohm et al. 2013. Values vary depending on the considered country and the year of construction. Increasing project experience reduces risk premiums and lowers financing costs for offshore wind and electrolysis in the long term. In order not to include an additional variable, a plausible average interest rate for the next 30 years was chosen.

Comparison of cost assumptions for hydrogen production cost in different studies and publications

Assumptions	Hy3 cost assumptions for green hydrogen from offshore wind in the North Sea		IEA hydrogen in North-Western Europe	EWI policy brief: H2 supply cost for Germany		2020 Hydrogen Economy Outlook (BNEF)	
	2030	2050	2030	2030	2050	2030	2050
Scope	Offshore wind in EEZ (NL, DE), onshore/offshore electrolysis		Offshore wind & H2 in BE, DK, FR, DE, NL, NO, UK	Offshore wind, Onshore Electrolysis Germany		Global estimates	
LCOH	4.16–6.30 €/kg	3.99–4.86 €/kg	2.50–3.50€/kg	3.55–4.06 €/kg	2.29–2.84 €/kg	1.07–2.41 €/kg	0.63–1.43 €/kg
WACC	5%; 25y system lifetime		6%; 30y system lifetime	8%; 25y system lifetime		-	
LCOE [€/MWh]	71–78 €/MWh	66–84 €/MWh	38–70 €/MWh	65–71 €/MWh	47–51 €/MWh	19 (AU PV) 25 (CN WI) 42 (JP WI)	11 (AU PV) 15 (CN WI) 30 (JP WI)
Load factor	10–55%	28–57%	40–60%	-		-	
Capex El.	590/679 €/kW (on-/offshore)	471/542 €/kW (on-/offshore)	581 €/kW el.	357–558 €/kW ($400–625/kW)	179–402 €/kW ($200–450/kW)	-	
Opex El.	10–27 €/kW*a (on-/offshore)	7–22 €/kW*a (on-/offshore)	1.6% of Capex	2% of Capex		-	
Efficiency	68.2%	70.0%	69%	68%	75%	-	

B3 Decarbonisation potential

Assumptions on the CO_2 footprints of the reference fuels/energy carriers

LCOH	**Levelied Cost of Blue Hydrogen [€/kg]**	**values**
LHV	Lower heat value of hydrogen	33.3 kWh/kg
η	System efficiency in % for NGR with CCS	69%
i	Interest/discount rate (as in a fixed annuity approach)	5%[47]
O&M	Maintenance and operation cost, typically a fixed percentage p.a. of CAPEX	3%
CAPEX	Annuity of the total specific investment cost of the NGR with CCS plant [$/kW H_2]	depends on reference year
Availability	The NGR with CCS plant has an assumed availability of 95%.	8,322 h
Gas price	Cost of gas purchase [€/kWh]	depends on reference year
CO2 price	A CO_2 price has been included in the calculation accordingly to the EU-ETS system [€/t]	depends on reference year

Reference fuel, energy carrier	**CO_2 footprint**	**Assumptions and sources**
Fossil fuel comparator (EU)	0.0940 kg CO_2/MJ	- Value was defined by the EU Commission for calculation of emissions of biofuels as a comparator for fossil fuels in transport sector. According to Article 25 paragraph 2 and Annex V of Directive (EU) 2018/2001 of the European Parliament and of the Council. [8]
Natural gas (methane)	0.0730 kg CO_2/MJ	- Upstream emissions of natural gas: 0.01694 kg CO_2/MJ CH_4[48] [5] - CO_2 emission factor of methane combustion: 0.0561 kg CO2/MJ - Value matches IPCC 2006 Guidelines [7,4]
Grey H_2 (Imported gas)	0.0988 kg CO_2/MJ (11.86 kg CO_2/kg H_2)	- Source: Timmerberg, 2020 - Process: SMR without CCS - Methane demand of SMR (without carbon capture): 185.6 MJ/kg H_2 - Upstream emissions of natural gas: see natural gas assumptions [7,5]

[48] (Conversion of given value 61 g CO_2/kWh CH_4)
The value for upstream emissions of natural gas is the mean of four European supply chains with pipelines transport Russia (7,000 km), Middle East (4,000 km), Norway (1,300 km) and LNG transport [7] with a methane leakage rate of 1.7% [5].

Blue H_2 (imported gas)	0.0458 kg CO_2/MJ (= 5.49 kg CO_2/kg H_2)	- Source: Timmerberg, 2020 - Process: SMR with CCS (carbon capture rate: SMR: 90%) - Methane demand of SMR with CCS: 194.9 MJ/kg H_2 - Upstream emissions of natural gas: see natural gas assumptions [7,5]
Blue H_2 (domestic gas)	0.0185 kg CO_2/MJ (= 2.22 kg CO_2/kg H_2)	- Source: North Sea Energy, 2020 - Process: SMR with CCS (carbon capture rate: SMR: 95%) - Emissions of natural gas production: 0.12 kg CO_2/m^3
Green H_2 (offshore wind-North Sea)	0.01 kg CO_2/MJ (1.2 kg CO_2/kg H_2)	- Source: North Sea Energy, 2020 - Carbon footprint of wind energy production: 0.01 kg CO_2/kWh

C. Appendix: Transport scenarios

C1 Technical challenges of infrastructure modifications

Technically, numerous processes and mechanisms could occur depending on the type/condition of steel and hydrogen conditions (Robertson et al., 2015). A common starting point is hydrogen diffusion into the steel, which could eventually weaken steel strength and/or cause cracking (Huising & Krom, 2020; Krom, 2020; Trouvé et al., 2019). Hydrogen molecule catalysis by steel produces atomic hydrogen. Diffusion of atomic hydrogen into steel is an essential step in the embrittlement process. Upon diffusion into steel grain lattice, atomic hydrogen can induce decohesion by weakening the molecular bonds within steel. These weak bonds lead to dislocation, which in combination with other potential defects leads to plasticity and eventually failing under stress. An effective rate of hydrogen crack growth also depends on the pressure and temperature. In a recent workshop (Krom, 2020), Gasunie presented lab experiments concluding that crack growth is less than 0.022 mm over a 100-year period with 6.6 bar daily pressure cycle for an assumed defect in pipe welding. This growth rate is not projected to pose integrity risks for 100% hydrogen at 66 bar.

Presence of coatings (such as an oxide layer inside pipelines) could provide barrier for embrittlement as catalysis and diffusion of atomic hydrogen is the first step in embrittlement. Addition of O_2, CO_2, or CO molecules to the hydrogen could also have an inhibiting effect on embrittlement (Staykov et al., 2014). These solutions to reduce the effect of hydrogen on steel are being investigated in the Hydelta project (Hydelta, 2020).

C2 Network topology

The hydrogen transport network described in Section 5.2.1 is represented by a series of nodes and edges/connections. The nodes consist of demand, supply, import and storage location. The edges/connections consist of pipe segments identified by a unique pipe ID. Each pipe segment is represented by the number of lines, nominal pipe size (inches) and its hydrogen transport capacity (metric tons/hr). For reference, Figure 58 shows the network topology with the number of lines and the pipe ID. Note that the pipe ID is unique within each network topology, but not universally unique. That means that pipe ID 1 for the “default” network is not the same as pipe ID 1 in ‘WithRotterdamDEpipe’ network. The data is also listed in the tables below.

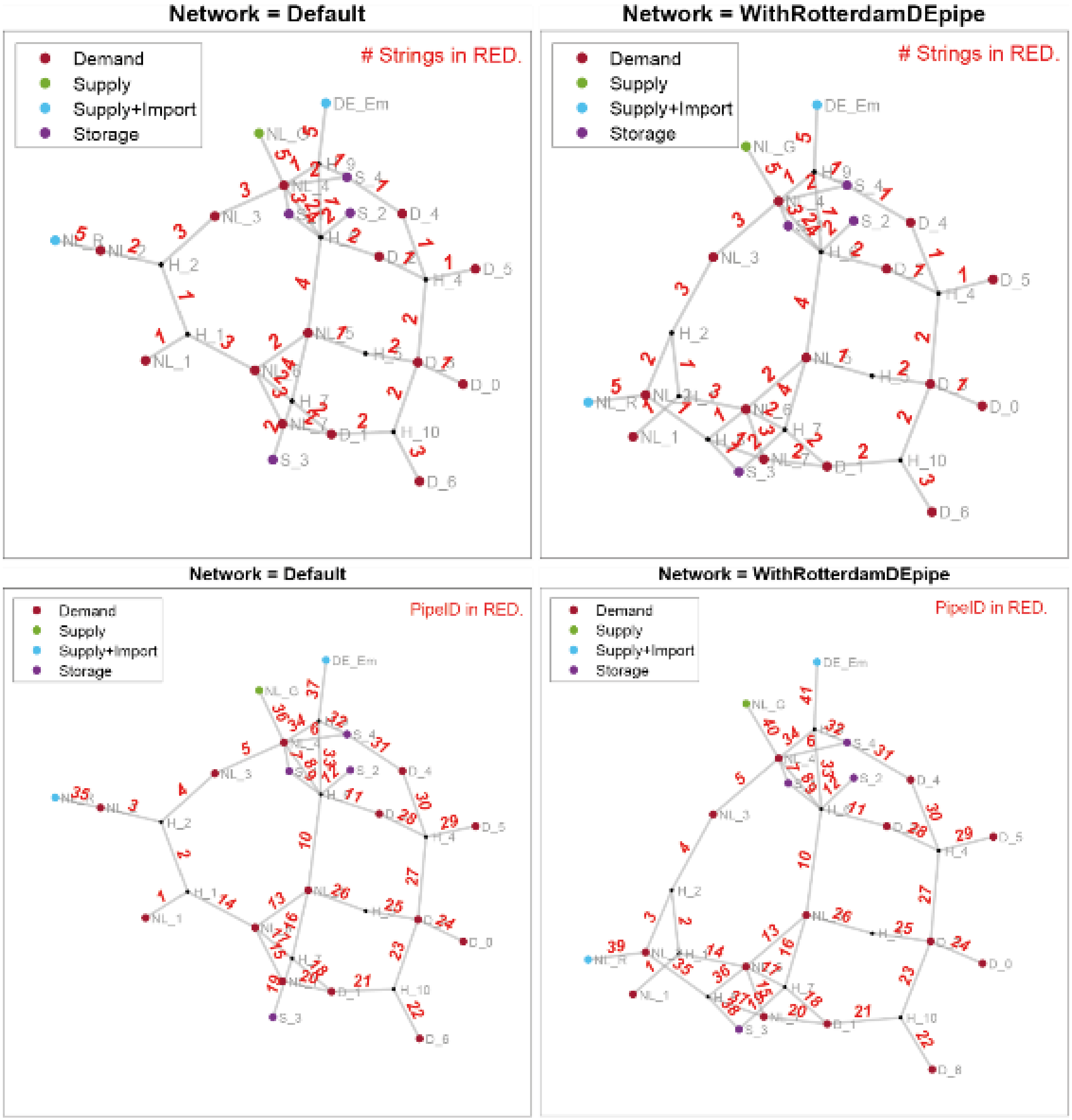


Figure 56: Network topology diagrams showing the number of lines (top two figures) and the pipe IDs (below two figures). The left column is for the default network, whereas the right column is the network with Rotterdam–Ruhr pipe segment, in addition to the default network.

List of nodes and their type for "Default" and "WithRotterdamDEPipe" network topology

Network = Default			Network = WithRotterdamDEPipe		
Nodes	**Node ID**	**Type**	**Nodes**	**Node ID**	**Type**
NL_1	1	Demand	NL_1	1	Demand
NL_2	2	Demand	NL_2	2	Demand
NL_3	3	Demand	NL_3	3	Demand
NL_4	4	Demand	NL_4	4	Demand
NL_5	5	Demand	NL_5	5	Demand
NL_6	6	Demand	NL_6	6	Demand
NL_7	7	Demand	NL_7	7	Demand
D_0	8	Demand	D_0	8	Demand
D_1	9	Demand	D_1	9	Demand
D_2	10	Demand	D_2	10	Demand
D_3	11	Demand	D_3	11	Demand
D_4	12	Demand	D_4	12	Demand
D_5	13	Demand	D_5	13	Demand
D_6	14	Demand	D_6	14	Demand
S_1	15	Storage	S_1	15	Storage
S_2	16	Storage	S_2	16	Storage
S_3	17	Storage	S_3	17	Storage
S_4	18	Storage	S_4	18	Storage
H_1	19	Hub	H_1	19	Hub
H_2	20	Hub	H_2	20	Hub
H_4	21	Hub	H_4	21	Hub
H_5	22	Hub	H_5	22	Hub
H_6	23	Hub	H_6	23	Hub
H_7	24	Hub	H_7	24	Hub
H_9	25	Hub	H_8	25	Hub
H_10	26	Hub	H_9	26	Hub
DE_Em	27	Supply (+ import optionally)	H_10	27	Hub
NL_R	28	Supply + import	DE_Em	28	Supply (+ import optionally)
NL_G	29	Supply	NL_R	29	Supply + import
			NL_G	30	Supply

Table 12: Network topology database consisting of pipe ID, node connections, distance, pipe size and number of lines

Network = Default							Network = WithRotterdamDEPipe					
PipeID	From	To	Distance (km)	Diameter (jnches)	Lines (#)		PipeID	From	To	Distance (km)	Diameter (jnches)	Lines (#)
P1	NL_1	H_1	46.4	24	1		P1	NL_1	H_1	46.4	24	1
P2	H_1	H_2	63	32	1		P2	H_1	H_2	63	32	1
P3	H_2	NL_2	51.2	36	2		P3	H_2	NL_2	51.2	36	2
P4	H_2	NL_3	84	48	3		P4	H_2	NL_3	84	48	3
P5	NL_3	NL_4	200.3	36	3		P5	NL_3	NL_4	200.3	36	3
P6	NL_4	S_4	39.4	24	2		P6	NL_4	S_4	39.4	24	2
P7	NL_4	S_1	43.3	36	3		P7	NL_4	S_1	43.3	36	3
P8	NL_4	H_6	24.5	36	2		P8	NL_4	H_6	24.5	36	2
P9	S_1	H_6	18.8	48	4		P9	S_1	H_6	18.8	48	4
P10	H_6	NL_5	121.3	48	4		P10	H_6	NL_5	121.3	48	4
P11	H_6	D_2	106.5	36	2		P11	H_6	D_2	106.5	36	2
P12	H_6	S_2	138.4	24	2		P12	H_6	S_2	138.4	24	2
P13	NL_5	NL_6	63.4	48	2		P13	NL_5	NL_6	63.4	48	2
P14	NL_6	H_1	107.4	48	3		P14	NL_6	H_1	107.4	48	3
P15	NL_6	NL_7	106.9	48	3		P15	NL_6	NL_7	106.9	48	3
P16	NL_5	H_7	27.7	48	4		P16	NL_5	H_7	27.7	48	4
P17	NL_6	H_7	35.8	48	2		P17	NL_6	H_7	35.8	48	2
P18	H_7	D_1	110	36	2		P18	H_7	D_1	110	36	2
P19	H_7	S_3	38.8	36	2		P19	H_7	S_3	38.8	36	2
P20	NL_7	D_1	85.1	32	2		P20	NL_7	D_1	85.1	32	2
P21	D_1	H_10	22.7	36	2		P21	D_1	H_10	22.7	36	2
P22	H_10	D_6	47.2	36	3		P22	H_10	D_6	47.2	36	3
P23	H_10	D_3	107.7	36	2		P23	H_10	D_3	107.7	36	2
P24	D_3	D_0	86.6	40	1		P24	D_3	D_0	86.6	40	1
P25	H_5	D_3	30.4	40	2		P25	H_5	D_3	30.4	40	2
P26	NL_5	H_5	62.4	36	1		P26	NL_5	H_5	62.4	36	1
P27	D_3	H_4	120.4	32	2		P27	D_3	H_4	120.4	32	2
P28	D_2	H_4	90.6	36	1		P28	D_2	H_4	90.6	36	1
P29	H_4	D_5	165.1	40	1		P29	H_4	D_5	165.1	40	1
P30	D_4	H_4	58.5	32	1		P30	D_4	H_4	58.5	32	1
P31	D_4	S_4	119.3	48	1		P31	D_4	S_4	119.3	48	1
P32	H_9	S_4	23.9	40	1		P32	H_9	S_4	23.9	40	1
P33	H_9	H_6	22.1	40	1		P33	H_9	H_6	22.1	40	1

P34	H_9	NL_4	15.9	40	1		P34	H_9	NL_4	15.9	40	1
P35	NL_R	NL_2	0.1	48	5		P35	NL_2	H_8	177	36	1
P36	NL_G	NL_4	0.1	48	5		P36	H_8	NL_6	62	48	1
P37	DE_Em	H_9	0.1	48	5		P37	H_8	NL_7	43	48	1
							P38	H_8	S_3	43	24	1
							P39	NL_R	NL_2	0.1	48	5
							P40	NL_G	NL_4	0.1	48	5
							P41	DE_Em	H_9	0.1	48	5

C3 Transport analysis network model

The model that has been applied in this study consists of a network flow solver that balances hydrogen flow in an interconnected network of nodes and edges. A node is a specific geographic location where hydrogen is either removed from or added to the network. An edge is a connection between two nodes. For example, nodes represent supply, demand, storage and import locations on a map, whereas edges represent the hydrogen transport grid (see Figure **35**). In a network, multiple solutions could lead to a balanced grid operation. Therefore, we use the flow distance to quantify the effective distance over which hydrogen flows in the network. Flow distance ϕ_i is defined as the product of the length l_i (km) and flow rate f_i (metric tons/hr) of pipe segment i.

$$\phi_i = l_i \times f_i$$

The shortest transport route between supply and demand nodes could then be determined by minimizing the sum of all flow distances in the network. Mathematically, we translate this insight to the following objective function $J(f_i)$

$$J(f_i) = \sum_i \phi_i$$

This objective function is minimised by bounding the flow rates f_i between 0 and maximum flow capacity of pipe segment i. Reverse flow was allowed in the network. Additionally, the following constraint is imposed on the minimisation problem: Net flow balance at each node j, at each time step k, N_j^k is zero. That is, no flow is accumulated at each node at each time step.

Net flow balance at each node N_j is calculated from the difference between *supply, import and storage in production mode* and *demand, export and storage in feed-in mode*, and which effectively reads as:

$$N_j = \text{In} - \text{Out}$$

$$N_j = \left(S_j^k + I_j^k + c_j^k\right) - \left(D_j^k\right)$$

Here, S_j^k is the hydrogen supply, D_j^k is the hydrogen demand, I_j^k is the hydrogen import at the port of Rotterdam (Netherlands) or the port of Wilhelmshaven (Germany) and c_j^k is the hydrogen storage. Subscript j denotes node and superscript k denotes time step. The supply S_j^k and demand D_j^k as estimates in the network calculation are based on the analysis in Sections 3 and 4. The import I_j^k and storage c_j^k values are based on the annual import and storage needs as calculated in Section 5.4.1. We assumed a flat import rate over a given year. We also assumed an equal split between all the storage locations considered in specific scenario combination. Additionally, we assumed that total storage rate for NL and NRW is equally split across the four storage sites in order to estimate c_j^k. For example, if at a certain moment in the year there is more supply (import + production) than demand, then the storages are filled with an equal rate for all storage sites. There is no optimal dispatch of storage sites assumed across the network.

$$\text{Annual Import} = \text{ Annual demand - Annual supply}$$

$$\text{If import at the port of Rotterdam, } I_j^k \text{ (GWh/hr)} = \frac{\text{Annual Import (GWh)}}{\text{8760 (hr)}} \text{ (where } j = \text{ NL\_R)}$$

$$\text{If import at the port of Rotterdam \& the port of Wilhelmshaven,}$$
$$I_j^k \text{ (GWh/hr)} = 0.5 \times \frac{\text{Annual Import (GWh)}}{\text{8760 (hr)}} \text{ (where } j = \text{NL\_R \& DE\_Em)}$$

The formulae above were used when demand is greater than supply. Naturally, in the situation where supply is greater than demand, then similar formulae could be used to calculate annual export.

In order to estimate the hydrogen storage capacity needed to accommodate fluctuations in one year, we calculated the instantaneous hourly deficit/excess c^k at hour k as

$$c^k = \sum_j D_j^k - \sum_j S_j^k$$

The model assumes all storage is split equally between all the four sites (that is, $c_j^k = c^k/4$). The storage site charge, C^k for entire network in a year containing k hours could then be calculated as,

$$C^k = \sum_{k=1}^{8760} c^k$$

Here, C^k represents the storage site charge over a given year for the entire network consisting of four salt cavern sites. Figure **58** shows the annual storage site charge for a scenario in 2030 and in 2050 as an example. The hydrogen storage capacity required is then defined as

$$\text{Storage capacity} = \max_k C^k - \min_k C^k$$

Annual import is estimated by assumed that at the end of a year. There is no net deficit or excess hydrogen present. See Figure 57 for an example.

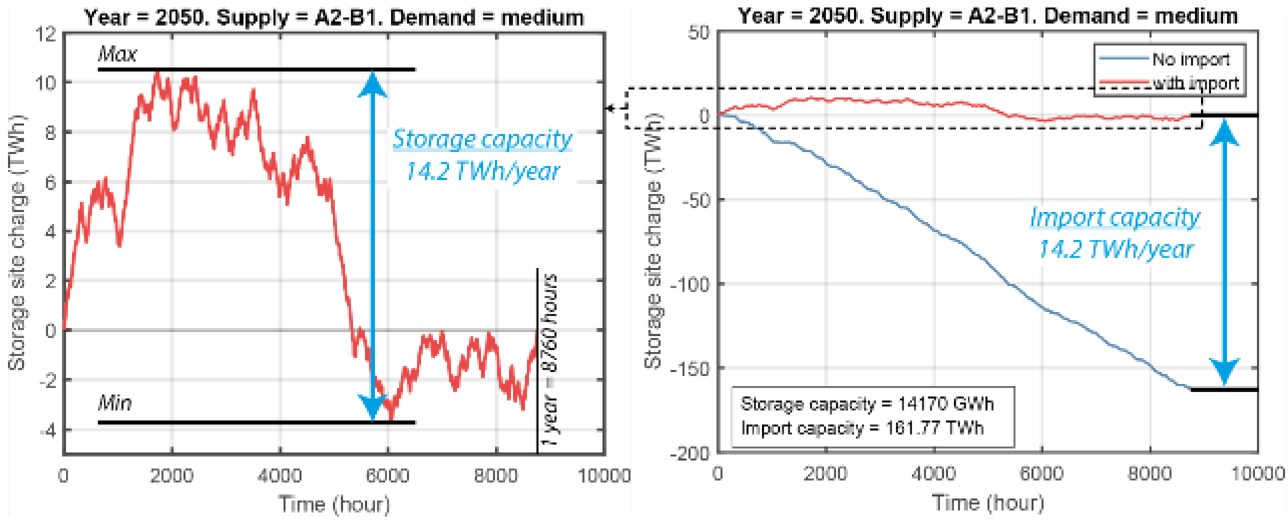


Figure 57: [left] Annual storage site charge for 2050 assuming import. [right] The storage site charge without import and with import

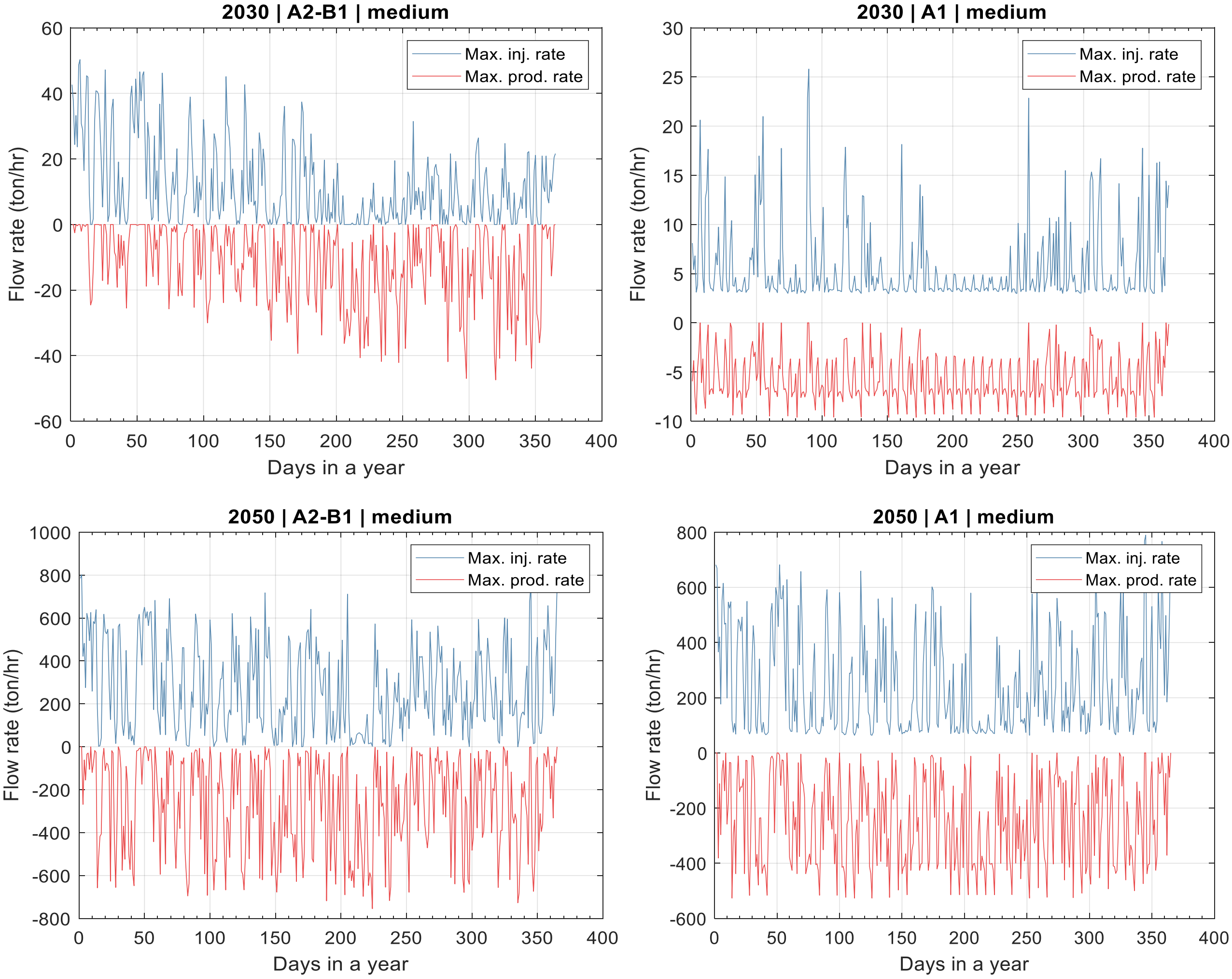


Figure 58: Plots showing the maximum injection and production rate for four scenarios

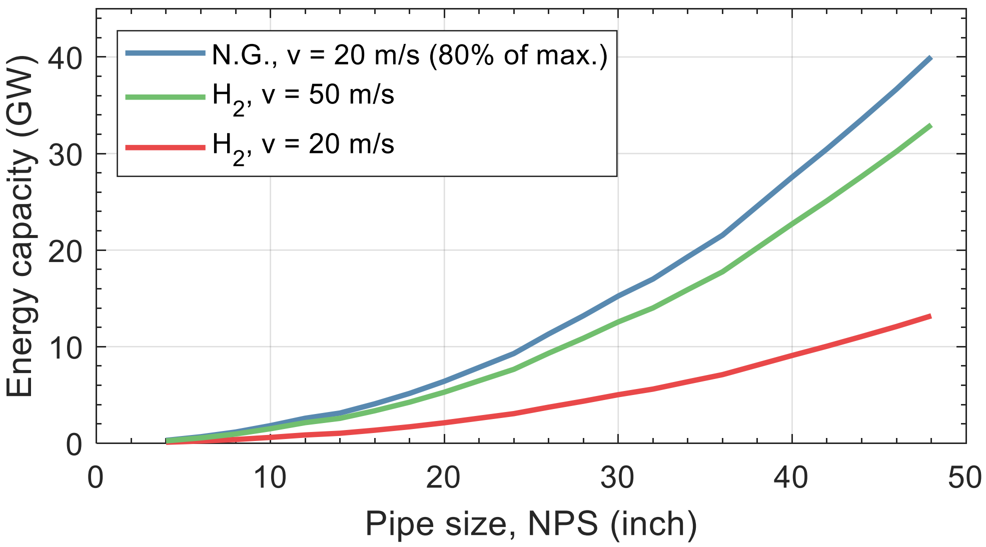


Figure 59: Pipeline capacity comparison

C4 Transport scenarios

Year 2030

The flow in pipe segment between NL_R and NL_2 (pipe ID 35, network default) would be a sum of hydrogen produced from electrolysis using electricity generated from offshore wind farm and the import of hydrogen from overseas at the port of Rotterdam. In Figure **60**, we show the level of detailed flow profiles analysed with two examples – P35 and P2.

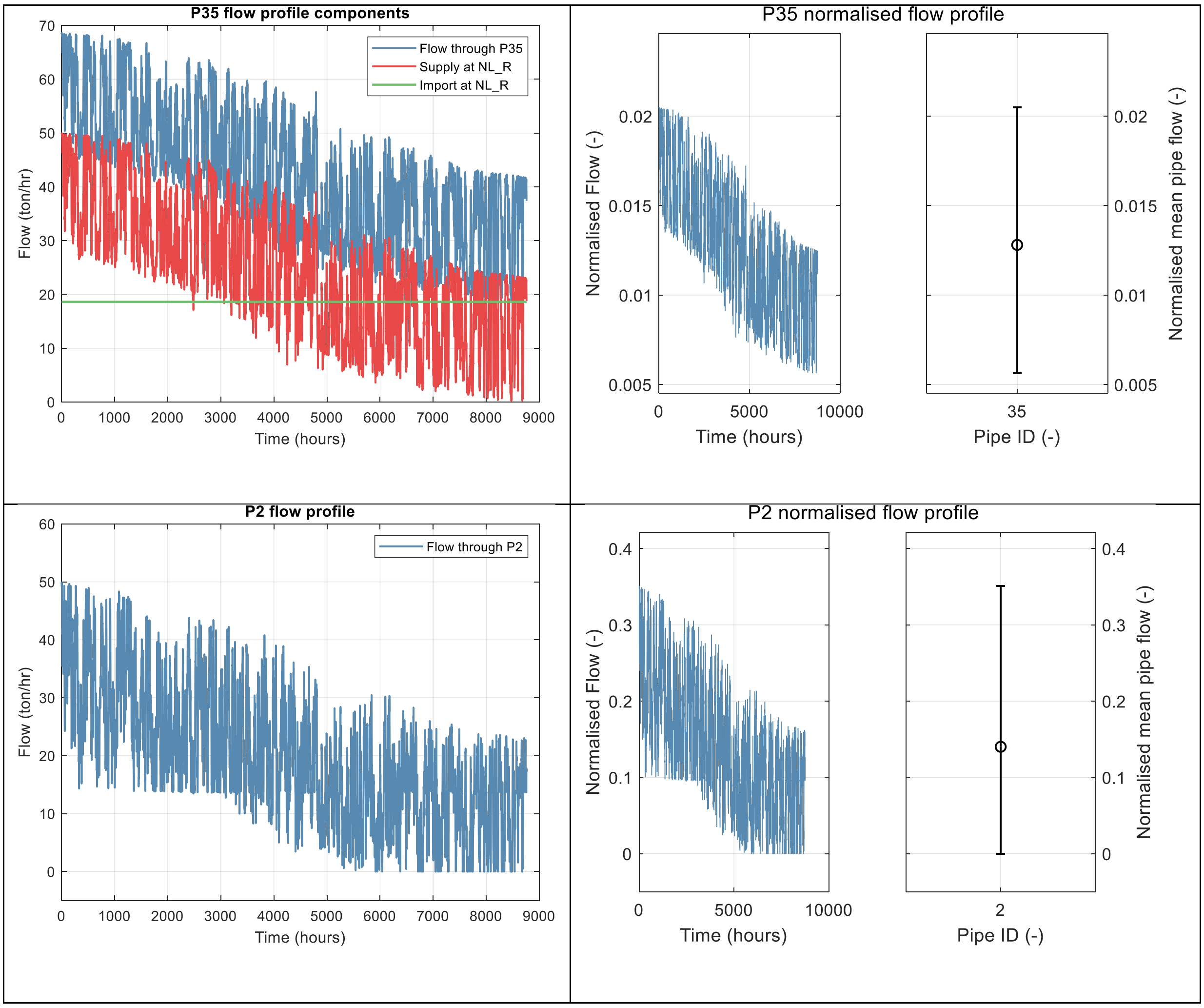


Figure 60: Plots showing annual flow profile for two pipe segments along with the normalised mean, min. & max. flow interval. (a) shows that the flow through P35 consists of supply and import at NL_R node. In (b), the normalised flow through P35 is shown along with the mean, min. & max. normalised flow. Similarly, (c) shows annual flow profile through P2 along with normalised profiles in (d).

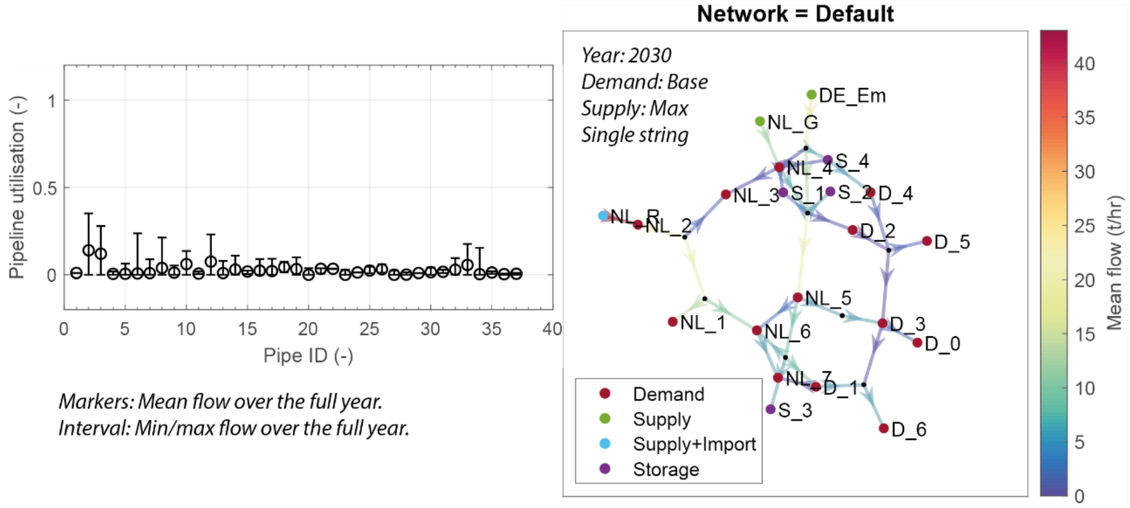


Figure 61: Simulation of single string network in 2030 showing that the grid capacities are sufficient to meet the projected transport needs. [Left] shows the normalised mean pipe flow and the min./max. flow interval. [Right] shows network topology with mean flow rate.

Year 2035 – single line network

In this section we show the single line network simulations for 2035. We can see that the single line capacities would be insufficient to meet the transport needs projects for 2035 (see Figure 62).

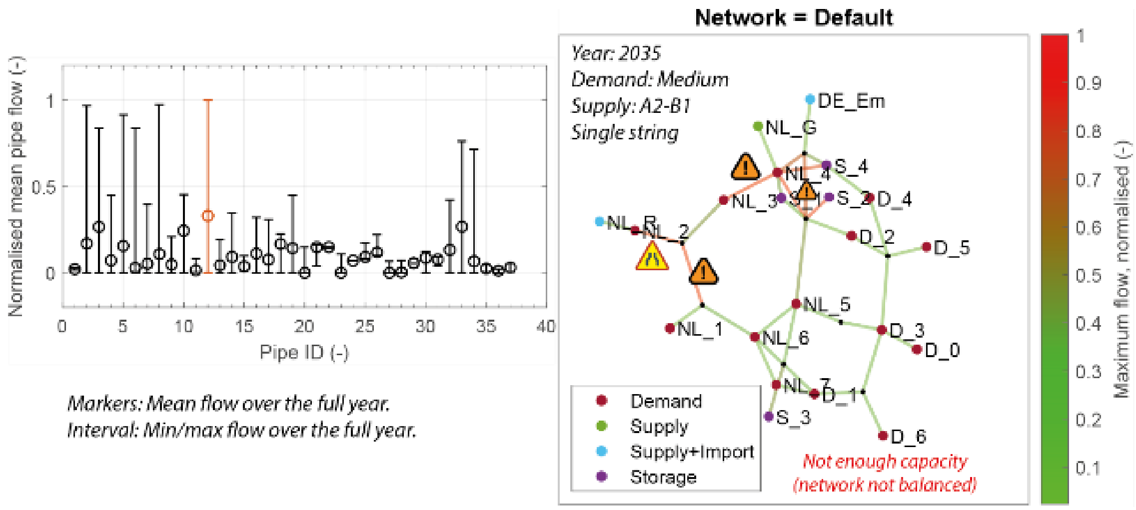


Figure 62: Simulation of single line network in 2035 showing that grid capacities are not sufficient to meet the projected transport needs. [Left] shows the normalised mean pipe flow and the min./max. flow interval. The yellow marker in the [right] network shows the pipe that is fully utilised.

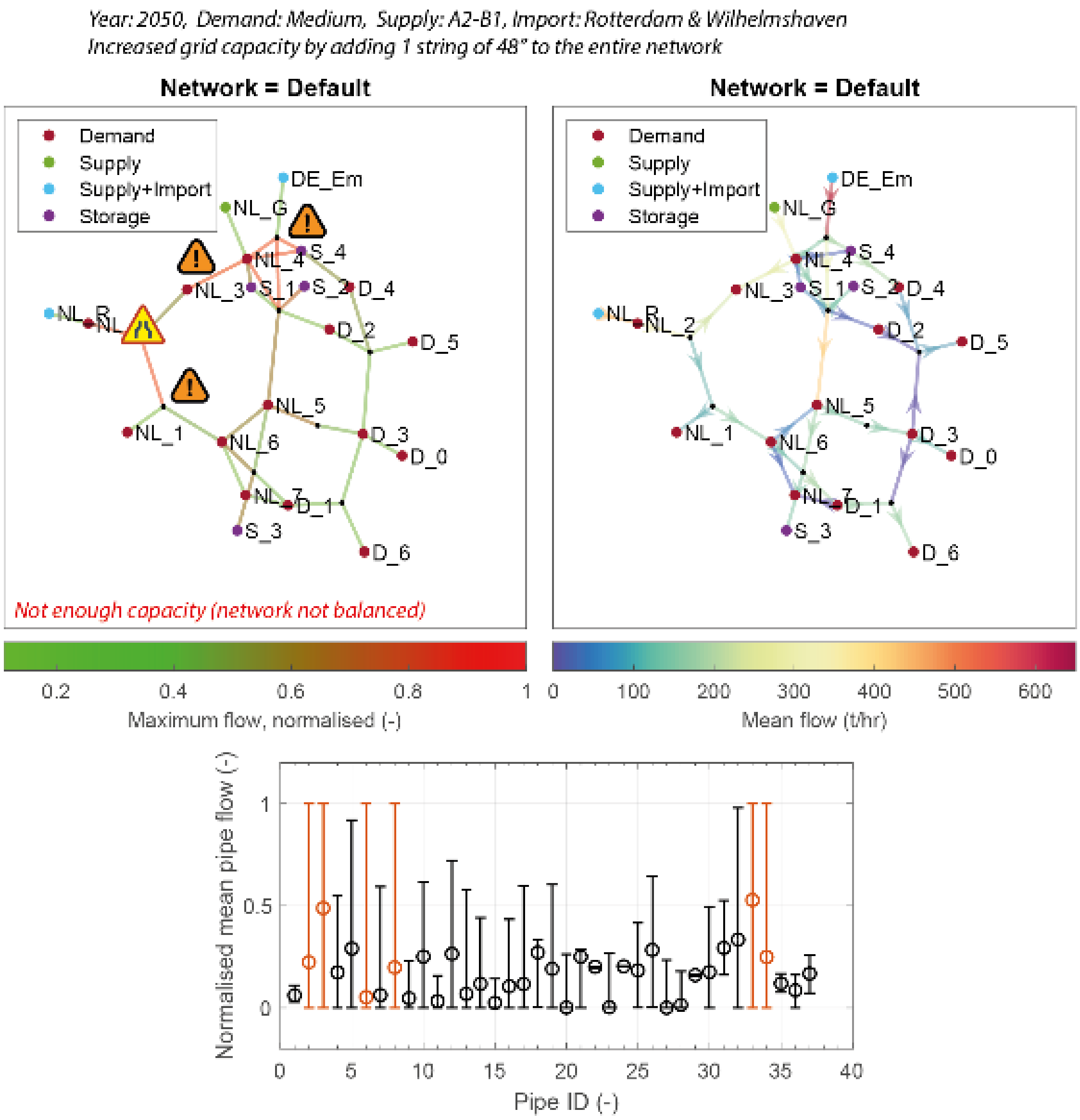


Figure 63: Detailed simulation results of the network expanded with one line of 48 inches. Note that the network is not balanced due to insufficient grid capacity. The yellow marking in the network diagram shows where bottlenecks occur, whereas the orange markings show full pipeline utilisation.

Year 2050

Detailed results for 2050, medium demand and maximum supply scenario. The network was assumed to be expanded by adding one line of 48 inches across the entire backbone. Note that the network is not balanced due to insufficient grid capacity (Figure 63).