Exploring the role of offshore wind power in the Dutch energy system in 2040

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The ballooning energy crisis triggered by the Ukraine war has dominated the news in 2022. Europe is battling a record-breaking price surge in energy prices, which strains household incomes and slows economic growth. The fuel supply disruptions come on top of the climate crisis, but unlike the oil crisis of the 1970s, the energy transition is gaining momentum. Researching the role of offshore wind in the future energy system of the Netherlands, a highly relevant topic to the current energy challenges, has been both challenging and rewarding.

With this thesis, I conclude my master's programme in Complex Systems Engineering and Management at the Technology, Engineering & Policy Analysis faculty of the TU Delft. This thesis would not have been possible without the help I received during the process. First, I would like to express my gratitude to my graduation committee. Thank you, prof. Kornelis Blok for the constructive feedback, guidance and, critical questions that have substantially improved the quality of the work. Your deep understanding of energy systems and ability to distinguish main issues from side issues were beneficial during the process. Also, I would like to thank dr. Özge Okur for her time and effort in providing feedback. Your feedback significantly improved the structure of the thesis.

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Summary

The Dutch government has the ambition to be climate neutral by 2050. An important pillar to realizing this ambition is to place large numbers of wind turbines in the North Sea. The Dutch cabinet decided in 2022 to realize around 21 GW offshore wind capacity in 2030, but the offshore wind demand in the Netherlands after 2030 remains uncertain. Estimations of the future offshore wind range from 38 GW to 72 GW in 2050. The upper bound of 72 GW offshore wind capacity is based on the technical potential of offshore wind in the Dutch part of the North Sea. However, this approach does not take a holistic approach to the energy system. It ignores essential system aspects such as the development of electricity demand, electricity trade, and the deployment of other low-carbon energy technologies. Hence, this thesis aims to answer the following main research question:

'What is the Dutch demand for offshore wind capacity in the North Sea in 2040 in a decarbonized energy system, considering future electricity demand, electricity trade, and security of supply?'

This research consists of two parts. First, the factors influencing future electricity demand in the Netherlands are examined, and estimations of energy supply in the Netherlands are analyzed. Electricity supply and demand in 2040 are studied by analyzing scenario studies that study the energy transition of the Netherlands. Special attention has been given to the influence of heat pumps in the built environment, electric vehicles in transportation, electrification in industry, and green hydrogen production on the evolution of electricity demand.

Second, the optimal system configurations of the North Sea countries (the Netherlands, Belgium, Denmark, France, Germany, Ireland, Luxembourg, Norway, Sweden, and the United Kingdom) are analyzed using the PyPSA-Eur model. Twenty-five scenarios are run with net-zero emission targets in 2040, illustrating the energy system effects. Relevant parameters varied to produce the scenarios include electricity demand in the Netherlands and bordering countries of the Netherlands, transmission system expansion, capital costs of generation and storage technologies, capacities of nuclear power, onshore and offshore wind power, and solar power in the system.

In the scenario analysis, the estimated electricity use is divided into five categories: built environment excluding heating, heating in the built environment, agriculture, industry, and hydrogen. The results show that the estimated electricity demand in the built environment is 59-67 TWh, and the estimated electricity demand for heating in the built environment is 16-29 TWh. Further, the electricity demand in agriculture is 12-25 TWh, the electricity demand for energy use for heating in industry is 69-118 TWh. and the electricity consumption for green hydrogen production is 0-292 TWh. Hence, the largest differences in the electricity demand estimations are caused by uncertainties about the role of hydrogen in the future, followed by electricity demand used for heating in industry.

Wind and solar energy are expected to play a crucial role on the supply side in a decarbonized Dutch energy system. According to the analyzed scenario studies, capacity estimations for offshore wind, onshore wind, and solar power are 28-72 GW, 6-20 GW, and 36-125 GW, respectively. Conventional generation using green hydrogen or biomethane as fuel provides flexibility to the system. Moreover, nuclear power and other low-carbon energy technologies will play a minor role in the future power supply according to the scenarios.

Additionally, several parameters are varied in the power system modeling to examine the energy system effects. The most important results of the modeling are as follows:

1. It has been shown that constraining the transmission expansion increases the optimal amount of offshore wind capacity in the Netherlands, and it increases the annual system costs of the North Sea countries. This is because the electricity exports of the Netherlands to neighboring countries increase when transmission expansion is constrained. In addition, more energy storage is needed when transmission expansion is constrained. Also, it has been found that most of the cost benefits of expanding the transmission system can be captured with half of the transmission volume.
2. Installing more onshore wind, nuclear power, or solar power capacity in the Netherlands decreases the optimal offshore wind capacity in the Dutch part of the North Sea. Furthermore, installing more capacity of these other low-carbon energy technologies in the Netherlands lead to more electricity exports to neighboring countries. When more onshore wind and nuclear power capacity is deployed in neighboring countries of the Netherlands, Dutch electricity exports decrease.
3. Higher electricity demand in the Netherlands or bordering countries of the Netherlands increases the optimal amount of offshore wind capacity in the Netherlands. This is because a higher electricity demand requires more generation to cover demand, and the demand for energy storage increases with higher electricity demand. Moreover, net electricity exports decrease when the electricity demand of the Netherlands increases. Further, net Dutch electricity exports increase when electricity demand in bordering countries of the Netherlands increases.

In conclusion, the results of the scenario analysis show that without hydrogen production, the electricity demand of the Netherlands in a highly decarbonized energy system ranges from 177 TWh to 270 TWh. In contrast, electricity demand, including hydrogen, ranges from 177 TWh to 562 TWh. Hence, electrification in the built environment, agriculture, transport, and industry creates sufficient electricity demand for the lower bound of 38 GW offshore wind capacity. It is unlikely that sufficient demand can be created for the higher bound of 72 GW offshore wind capacity without green hydrogen production in the Netherlands, even if offshore wind power will become the dominant energy generation technology in the Netherlands in 2040.

From the modeling results, it was found that the optimal amount of offshore wind capacity in the Netherlands is negatively impacted by the capacity of other low-carbon energy technologies in the Netherlands and in bordering countries of the Netherlands. Higher electricity demand in bordering countries of the Netherlands positively impacts the optimal capacity of offshore wind in the Netherlands due to its influence on electricity trade. Further, constraining the transmission system expansion leads to higher energy storage requirements in a highly decarbonized energy system, which leads to higher offshore wind capacity in the cost-optimized system. Hence, this research highlights that choices have to be made about the role of the Netherlands as an electricity importer or exporter and whether the Netherlands aims to use its renewable energy to produce green hydrogen domestically or import hydrogen from abroad.

Lastly, several uncertainties remain in the model that can be explored in further research. First, the battery storage capacity in the model is very low. A possible explanation of the low battery storage capacity in the model is the cost assumptions of energy storage. Second, the imposed onshore wind constraints led to much electricity flow from Scandinavia to Germany. In further research, different capacity constraints can be used.

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List of Abbreviations

AF	Annuity factor
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CSP	Concentrated solar power
CO_2	Carbon dioxide
CoSEM	Complex Systems Engineering and Management
DSO	Distribution system operator
EEZ	Exclusive economic zone
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EUR	Euro
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
GW	Gigawatt
H_2	Hydrogen
HDV	High-duty vehicle
HVAC	High voltage alternating current
HVDC	High voltage direct current
ICE	Internal combustion engine
II3050	Integrale Infrastructuurverkenning 2030-2050
KEV 2021	Klimaat- en Energieverkenning 2021
KIVI 2020	Design of a Dutch carbon-free energy system EnergyNL2050
LDV	Low-duty vehicle
MGA	Modeling to generate alternatives
OCGT	Open cycle gas turbine
OPEX	Operating expenditures
PV	Photovoltaic
RFNBO	Renewable fuels of non-biological origins
RSQ	Research sub-question
TNO 2022	Towards a sustainable energy system for the Netherlands in 2050
TSO	Transmission system operator
TWh	Terawatt-hour
TYNDP 2022	TYNDP 2022 Scenario Report
UK	United Kingdom
Werkgroep extra opgave	Alles uit de kast – Een verkenning naar de opgaven voor het Nederlandse elektriciteitssyteem van 2030

1. Introduction

1.1. Research problem

The rise of CO_2 levels in Earth's atmosphere has raised concerns about the risks of anthropogenic climate change and these adverse effects and risks are becoming increasingly complex and more difficult to manage (Pörtner et al., 2022). Additionally, Russia's ongoing aggression towards Ukraine and the consequent spiraling natural gas and electricity prices has led to energy security concerns in the European Union. In response to the climate, and gas crises, most EU countries have stepped up their ambition of renewable energy deployment since 2019 while decreasing planned 2030 fossil generation (Czyżak et al., 2022).

The Netherlands intends to become a front-runner in Europe in combating climate change. The ambition of the Dutch government is to be climate neutral in 2050 and to reduce CO_2 emissions by 55% in 2030, with a policy aim set at a reduction of 60% relative to 1990 (Rijksoverheid, 2021, p.6). The energy sector is a major emitter of CO_2 in the Netherlands, and in 2020, most of the Dutch energy supply came from natural gas, followed by crude oil and renewables (PBL, 2021, p.217). Offshore wind power is a promising renewable technology to decarbonize the Dutch energy system due to its large technical potential in the North Sea. Moreover, the average installed costs of offshore wind power in Europe declined by 43% between 2010 and 2021 (International Renewable Energy Agency, 2022, p.111). As a result, the Dutch policy goal is to have 21 GW of offshore wind capacity installed by 2030 (Ministerie van Economische Zaken en Klimaat, 2022a).

However, the role of offshore wind power in the Dutch energy system after 2030 is yet to be determined. The Dutch Ministry of Economic Affairs and Climate Policy is investigating whether 50 GW offshore wind capacity in 2040 and 70 GW offshore wind power in 2050 is realistic (Ministerie van Economische Zaken en Klimaat, 2022b, p.3).

Furthermore, the North Sea Outlook estimates that the offshore wind capacity in the Netherlands ranges from 38 GW to 72 GW (Cleijne et al., 2020, p.6). These estimations are based on the Integrale Energieverkenning 2030-2050 (II3050), a scenario study by Netbeheer Nederland. The conclusions of the II3050 form the basis of the investment plans for all electricity and gas DSOs and TSOs in the Netherlands (Netbeheer Nederland, 2021, p.191). The upper bound of 72 GW offshore wind power in 2050 can be found in the 'National Steering' scenario (den Ouden et al., 2020, p.26), and the lower bound of 38 GW offshore wind capacity is part of the 'International Steering' scenario. These numbers are not modeling outcomes but are selected to explore the Netherlands' potential future energy systems (den Ouden et al., 2020, p.6). The upper limit of 72 GW of offshore wind power is based on a calculation made in another report, the Ruimtelijke Verkenning Energie en Klimaat. Here, it was reasoned that about 4-6 MW/km^2 could be realized when 10-14 MW wind turbines are used (Kuijers et al., 2018, p.64). Furthermore, it is mentioned that about eighteen thousand square kilometers of the North Sea are available for offshore wind, leaving around 40.000 km^2 available for other functions. Subsequently, if the lower bound of 4 MW/km^2 is taken and multiplied by 18.000 km^2, the technical potential of 72 GW offshore wind power for the Netherlands is calculated. Nonetheless, the same report mentions a maximum technical potential of 80 GW with the comment that this might be ambitious (Kuijers et al., 2018, p.296).

A more recent study reported that the Dutch Exclusive Economic Zone (EEZ) in the North Sea could host an installed capacity of around 59 GW on readily available space, and the offshore wind capacity can be increased to 99 GW when areas are selected that can be fit for co-use of multiple functions (Taminiau & van der Zwaan, 2022).

1.2 Research objective

It was found in the previous section that estimations of future demand for offshore wind turbines in the EEZ of the Netherlands after 2030 vary by a factor of two. In addition, future offshore wind capacity estimations in the II3050 are based on the technical potential of offshore wind power in the North Sea. This approach underexposes system effects because placing large numbers of wind turbines in the North Sea will influence the whole energy system of Northwestern Europe. For instance, the deployment of renewable power plants has a merit order effect in neighboring countries (Abrell & Kosch, 2022), and electricity demand must keep up with the electricity supply in order to keep a profitable business case for new offshore wind projects (Kolb et al., 2020). This thesis aims to generate insights into the factors that determine offshore wind demand in the Netherlands.

This research is relevant for policymakers and energy infrastructure companies. Electricity demand in the Netherlands has been relatively stagnant for over a decade (PBL, 2021, p.236), but electricity demand is expected to rise sharply in the coming years due to increased electrification of the economy (Werkgroep Extra Opgave, 2022). As a consequence, network companies make investments in expanding the electricity grid, and the expected future capacity of offshore wind should thereby be taken into account. Due to the lengthy lead times of technical projects, which are around five years for offshore projects and up to ten years for infrastructure projects (Cleijne et al., 2020, p.9), investment decisions for future energy systems must be made before 2030.

Moreover, a deeper understanding of the factors that influence the Dutch demand for offshore wind after 2030 benefits policymakers. Since offshore wind power can play a crucial role in decarbonizing the energy system of the Netherlands, it is relevant for policymakers to know how much offshore wind is needed because the tendering for offshore wind locations must be prepared. Furthermore, the results generate insights into whether measures are needed to increase electricity demand.

1.3 Temporal and spatial scope of the research

The Netherlands aims to be climate neutral by at the latest 2050 (Rijksoverheid, 2021, p.6), and the electricity system is relatively easy to decarbonize because renewable energy technologies are cost-competitive with fossil fuel technologies (International Renewable Energy Agency, 2022, p.34) . Since the electricity system can be carbon-neutral well before 2050, the time horizon for this research is set at 2040.

Furthermore, the research concentrates on the Netherlands but takes a European scope. The electricity system cannot be seen in isolation because there is a continuous flow of electricity across national borders within the European Union (Tennet, 2022, p.30). It is chosen to focus on the countries around the North Sea[1] because the European Union has made a strategy to have at least 300 GW of offshore wind capacity in the North Sea in 2050 (European Commission, 2020) and offshore wind capacity in the territorial waters of countries close to the Netherlands influence the Dutch energy system.

1.4. Research questions

The objective of this research is to explore the energy system effects of offshore wind power in the Dutch electricity system in 2040. The main research question is formulated as follows:

[1] These North Sea countries are Belgium, Denmark, France, Germany, Ireland, Luxembourg, Norway, Sweden, the United Kingdom and the Netherlands.

"What is the Dutch demand for offshore wind capacity in the North Sea in 2040 in a decarbonized energy system, considering future electricity demand, electricity trade, and security of supply?"

The main research question is divided into two sub-questions to make the research more tangible. First, it is essential to get an overview of the different factors that determine the future electricity demand of the Netherlands. Moreover, different technologies can produce low-carbon power, and the availability of these competing technologies influences the demand for offshore wind power. Hence, the first sub-question is as follows:

RSQ 1: "Which factors influence the future electricity demand in the Netherlands, and what are estimates of future renewable power generation in the Netherlands in a decarbonized energy system?"

After having an understanding of the factors that influence future electricity demand and renewable energy supply in the Netherlands, the energy system effects of offshore wind power can be analyzed in a European context. This leads to the second sub-question:

RSQ 2: "What configurations of offshore wind capacity, electricity demand, import and export of electricity, solar power capacity, and hydrogen import in 2040 lead to the lowest societal costs for the North Sea countries while being compatible with the Paris Climate Agreement and maintaining high security of supply?"

1.5. Research approach

In the previous sections, it was identified that the knowledge gap is related to a lack of understanding of the functioning of the socio-technical system, namely the system effects of installing large numbers of offshore wind turbines in the North Sea. Hence, a modeling approach is selected for this research.

Previous studies investigating future (low-carbon) energy scenarios for the Netherlands are analyzed to answer the first research sub-question. The added value of the scenario analysis is to obtain empirical insights into the future electricity demand of the Netherlands and renewable energy generation in the Netherlands (Wee & Banister, 2016, p.5). Here, an example of a qualitative difference between scenario studies could be the number of electric vehicles on the road in 2040. As a result, more electric vehicles will result in higher electricity demand, which will influence the demand for offshore wind capacity in the Netherlands. On the supply side, more electricity imports will also influence the demand for offshore wind capacity in the Netherlands. The results of the analysis are used as input to answer the second sub-question.

A techno-economic model is developed to answer the second sub-question. An advantage of a modeling approach is that system interventions can be investigated without real-life consequences. Experimentation with a real energy system is expensive and time-consuming because individual components cost millions, and it takes years for power plants and infrastructure projects to develop. A disadvantage of a modeling approach is that a model simplifies reality and the results' quality depends on the quality of the input data (Nikolic et al., 2019, p.6).

First, the electricity system of North-Western Europe will be conceptualized as a model consisting of nodes and edges. Thereafter, a literature review will gather data about electricity demand, renewable energy potentials, and costs and performance assumptions of electricity generation technologies. Second, generation, network, and storage capacities will be co-optimized, as well as the electricity dispatch of power plants and electricity storage facilities and power flow per time step. Based on the modeling results, insights are obtained into the factors that influence the role of offshore wind power in the Dutch energy supply.

1.6. Alignment to Complex Systems Engineering and Management (CoSEM)

This thesis addresses the role of offshore wind power in the future energy system of the Netherlands. Integrating large numbers of wind turbines in the EEZ of the Netherlands is not just an exercise of matching supply with demand but leads to significant system effects beyond the borders of the Netherlands. These effects also cross different sectors due to sector coupling via sustainable gases. For example, the average electricity price decreases when more wind power capacity is installed. This is caused by merit order shifts which deteriorates wind farm operators' business case (Kolb et al., 2020). In addition, subsidies might be necessary for a good business case for offshore wind power when electricity demand is insufficient. As a result, a more comprehensive understanding of the Dutch demand for offshore wind energy contributes to designing effective interventions in the energy system of Europe and aligns with the study program of CoSEM.

1.7. Thesis structure

The thesis is structured as follows: Chapter 2 presents a literature review from which the research gaps are derived. Chapter 3 describes the methodology used in this research. Chapter 4 shows the results of the scenario analysis. Chapter 5 gives a detailed description of the model, shows the input data, and discusses the experimental setup. Chapter 6 presents the modeling results. Chapter 7 discusses the results and limitations of the research. Finally, Chapter 8 answers the research questions, discusses this thesis' relevance to policymakers, and provides suggestions for future research. The appendices report on further details.

2. Literature review

This chapter provides a brief literature review from which the research gaps are derived. The academic research gap is identified by drawing from two fields of literature that are at the core of this research, renewable energy system transition and power system modeling. The search is limited by only considering publications written in English. The bibliographic search engine Scopus and Google Scholar are used to conduct the literature search. Also, snowballing is used to find relevant journal articles.

2.1. Literature table and findings

The reviewed articles are presented in Table 1. The comparison is based on several categories that are considered relevant. The first category reviews the geographical scope of the research and the effect of transmission on the power system. The second category reviews the modeling studies' sectoral scope and carbon reduction targets. The third category reviews how electricity demand is addressed in the literature. The fourth category reviews the methodology that is used in the modeling studies. The fifth category reviews the low-carbon electricity generation technologies used in the modeling studies. The role of hydrogen in the energy system is described in the sixth category. The last category reviews the estimations of offshore wind capacity in the North Sea.

Table 1: overview of the reviewed papers.

Overview of the reviewed papers.	Geographical scope	Temporal scope	Low-carbon energy technologies in power sector	Modeling tool
Martínez-Gordón et al. (2022)	North Sea region	2050	Solar, wind, hydropower, nuclear, biomass, CCGT	IESA-NS model
Bobmann & Staffell, (2015)	Germany, UK	2050	Solar, wind	eLOAD, DESSTinEE
Hörsch, Hofmann, et al. (2018)	Europe	2011	Solar, wind	PyPSA-Eur
Neumann & Brown (2021)	Europe	2020	Solar, wind, hydropower, CCGT, OCGT	PyPSA-Eur
Schlachtberger et al. (2018)	Europe	2030	Solar, wind, hydropower	PyPSA-Eur
Schlachtberger et al. (2017)	Europe	2030	Solar, wind, hydropower	PyPSA-Eur
Brown et al. (2018)	Europe	2011	Solar, wind, hydropower, OCGT	PyPSA-Eur-Sec-30
Victoria et al. (2019)	Europe	2015	Solar, wind, hydropower, OCGT	PyPSA-Eur-Sec-30
Scheepers, Palacios, Jegu, et al. (2022)	The Netherlands	2050	Solar, wind, biomass, CCGT	Opera
Tröndle et al., (2020)	Europe	2050	Solar, wind, hydropower, biomass	Calliope
Lombardi et al., (2020)	Italy	2050	Solar, wind, hydropower, biomass, CCGT, geothermal	Calliope
Child et al. (2019)	Europe	2050	Solar, wind, hydropower, biomass, nuclear	LUT model
Gils et al. (2017)	Europe	2050	Solar, wind, hydropower, CSP	REMix
Gea-Bermúdez et al. (2021)	Northern-central Europe	2050	Solar, wind, hydropower, CHP, OCGT, CCGT	Balmorel
Collins et al. (2017)	Europe	2030	Solar, wind	PLEXOS, PRIMES

2.1.1. Geographical scope, network expansion and international energy trade

From Table 1, it can be observed that the reviewed studies use different spatial scopes. Some studies focus on single countries such as Italy and the Netherlands (Scheepers, Palacios, Jegu, et al., 2022), and other studies focus on multiple countries like Germany and the United Kingdom (Bobmann & Staffell, 2015). Scheepers, Palacios, Jegu, et al., (2022) take power trade with neighboring countries into account, and the Netherlands will be a net exporter of electricity in 2050. However, neither electricity trading volumes with neighboring countries nor transmission system expansion are specified in this study. Lombardi et al., (2020) mention international transmission expansion as part of the cost-optimal solution but does not quantify whether Italy will be a net electricity importer or exporter.

The majority of the reviewed articles investigated the European electricity system. The European electricity system consists of the 30 countries in the major synchronous zones of the European Network of Transmission System Operators for Electricity (ENTSO-E), which consists of the EU-27 countries plus Norway, Switzerland, Serbia, Herzegovina, and the UK but without Cyprus and Malta. Half of the studies use the PyPSA-Eur model or a precursor. PyPSA-Eur is a comprehensive open model dataset of the European power system at the transmission network level that is suitable for both operational studies and generation and transmission expansion planning studies (Brown et al., 2018). An overarching effect found in these studies is the importance of network expansion in the European electricity system. Schlachtberger et al., (2017) found a non-linear relationship between total system costs and transmission system expansion. Further, an expansion of four times the transmission system's interconnection capacity in 2018 already enabled most[2] of the cost savings of the optimal transmission system (Child et al., 2019; Schlachtberger et al., 2017). Similarly, Tröndle et al., (2020) showed that expanding the renewable energy supply is the cheapest when using a continental scale. However, supplying on a national or subnational supply is possible for cost penalties of 20% or less. However, doing so leads to an unequal distribution of generation and transmission across Europe. Some countries in the cost-optimal system rely strongly on electricity imports, such as Belgium, the Czech Republic, and Germany[3]. Furthermore, Gils et al., (2017) found that power transmission capacity increases strongly with the wind supply share.

Moreover, some studies have focused on regions within the European Union. Gea-Bermúdez et al. (2021) used the energy system model Balmorel to optimize the capacity development and operation of the energy system in Northern-central Europe towards 2050. Transmission system expansion was allowed in this study, and it was found that sector coupling leads to increased transmission in the cost-optimal scenarios, and both sector coupling and transmission expansion should be encouraged. A study conducted by Martínez-Gordón et al. (2022) focused on the countries in the North Sea region. The interconnector capacities and the cross-border flows per country are reported. The Netherlands, Belgium, and Germany are net electricity importers , the United Kingdom and Norway have similar electricity imports and exports, while Denmark and Sweden are net electricity exporters. It was also found that additional interconnector capacity is beneficial to the system.

2.1.2. Sectoral scope and carbon constraints

Most studies focus on a system design with a large share of intermittent renewable energy technologies. Thereby, these studies assume a decarbonization target that has to be met in the future. Some studies assume a fully decarbonized electricity system (Child et al., 2019; Lombardi et al., 2020; Tröndle et al., 2020). Other studies assume a 95% CO_2 emission reduction target relative to 1990 (Schlachtberger et al., 2017, 2018). If

[2] 85% of the cost savings of the optimal can be achieved if the transmission system expands to four times.

[3] These countries produce less than 10% of their own demand (Tröndle et al., 2020, p.8).

some CO_2 emissions are allowed, gas turbines are often used as conventional backup systems. Neumann & Brown (2021) investigated cost-optimal solutions for a system targeting 80%, 95%, and 100%. It was shown that total system costs scale non-linearly with tight emission caps[4].

The previous studies only considered carbon reduction in the electricity system. The integration of high shares of renewable energy can be coupled with other energy sectors such as transport and heating. The PyPSA-Eur-Sec-30 model couples heat and transportation to electricity in a European context and enables a higher share (75%) of the final energy use to the model (Brown et al., 2018). It was shown that the cost-optimal use of electric vehicles, heat pumps, district heating, and seasonal thermal storage reduces the economic case for stationary electricity storage and reduces total system costs[5]. Victoria et al., (2019) showed that a higher reduction of global CO_2 emissions could be achieved with sector coupling before large storage capacities emerge. Neither coupling the transport sector nor the heating sector decreases the need for hydrogen storage, but sector coupling allows CO_2 emission reduction before hydrogen storage capacity is needed. Further, Gea-Bermúdez et al. (2021) investigated the role of sector coupling in Northern-central Europe when pursuing the energy transition to satisfy electricity and heat demand. It was shown that the power system moves from a system where generation adapts to demand to a system where demand adapts to generation.

Moreover, Martínez-Gordón et al. (2022) investigated optimal system configurations using an integrated energy system model. It was shown that a more interconnected offshore infrastructure, such as electric power, hydrogen, and carbon capture and storage (CCS) offshore grids, can be beneficial to the energy system. Power to liquids is identified as a key technology to reduce crude oil dependency and allows the integration of a large number of variable energy sources in the system. Biomass also plays a crucial role in meeting carbon reduction targets.

2.1.3. Electricity demand

Annual electricity demand per country is considered an exogenous variable in modeling studies. Some studies assume that electricity demand is constant and does not deviate much from today's levels (Child et al., 2019; Hörsch, Hofmann, et al., 2018; Neumann & Brown, 2021; Victoria et al., 2019). Other studies scale historic electricity demand profiles from the ENTSO-E to the future by utilizing an algorithm (Collins et al., 2017; Lombardi et al., 2020) or using a synthetic hourly profile of electricity demand (Child et al., 2019).

Bobmann & Staffell, (2015) explored the evolution of electric load curves to 2050. This study demonstrates that the shape of the electric load curve will change in the coming decades due to a transforming structure of electricity demand. The major drivers behind the load curve shift are the emergence of new technologies such as heat pumps, electric cars, efficiency improvements, and macroeconomic factors. Without smart management, the electricity demand for heat pumps and electric vehicles can increase the system load peak more strongly than the annual electricity demand.

Furthermore, some studies make their own electricity demand projections (Gils et al., 2017; Martínez-Gordón et al., 2022b; Scheepers, Palacios, Janssen, et al., 2022). Martínez-Gordón et al., (2022) project that the electricity demand in the residential and service sectors will increase by 7%, and electricity demand in agriculture will increase by 20% in 2050 relative to 2020. Scheepers, Palacios, Jegu, et al., (2022) project that Dutch electricity demand increases to more than 300 TWh in the ADAPT scenario and increases to more than 500 TWh in the TRANSFORM scenario.

[4] Achieving a CO_2 emission target of 95% relative to 1990 is a quarter more expensive than achieving a CO_2 emissions reduction target of 80%. Moreover, achieving a 100% CO_2 emissions reduction is 50% more expensive than achieving an 80% CO_2 emissions reduction.

[5] Sector coupling and cross-border transmission can reduce total system costs by 37%.

2.1.4. Modeling methodology

Another characteristic that distinguishes the reviewed studies is the adopted methodology. Bobmann & Staffell, (2015) used simulation models to examine the evolution of load curves. A simulation model allows the testing of configurations of the energy system and obtains indicators such as system costs, CO_2 emissions, and generator capacities. This technique does not guarantee that a lowest-cost solution will be found.

Most of the reviewed modeling studies use investment optimization and deal with the annual dispatch of the energy system, and the investments in capacity expansion are optimized. In these models, total annual system costs written as a linear problem are minimized (Gea-Bermúdez et al., 2021; Schlachtberger et al., 2017; Tröndle et al., 2020).

However, cost optimality alone ignores important social aspects. Near-optimal alternatives of renewable energy systems might be attractive due to properties such as social acceptance. Neumann & Brown (2021) explored the near-optimal feasible space of a renewable European electricity system using the modeling-to-generate-alternatives (MGA) methodology. It was demonstrated that a cost deviation of 0.5% already offers a wide range of possible investments. Nevertheless, either onshore or offshore wind energy, along with hydrogen storage, remains necessary for a 100% CO_2 reduction, and transmission network expansion is necessary to keep total costs within 10% of the optimum.

Moreover, hydrogen storage substitutes natural gas turbines and positively correlates with onshore and offshore wind capacities. Likewise, battery storage is correlated with solar installations, and transmission system expansion occurs in unison with more onshore and offshore wind power deployment. Lombardi et al. (2020) used the SPORES approach, which consists of a spatially explicit extension of the MGA method. When a higher investment margin is made available, it was shown that the coexistence of multiple strategies becomes available. The latter could reduce the costs of relying on a single strategy.

2.1.5. Low-carbon energy technologies considered

All articles included in Table 1 include solar energy and wind energy in the modeling, and almost all articles include hydropower. Some studies also include biomass-based electricity generation as an option for energy system flexibility (Child et al., 2019, p.14). Various studies include natural gas-based electricity generation when CO_2 emissions for electricity generation are allowed (Neumann & Brown, 2021; Victoria et al., 2019). According to Scheepers, Palacios, Jegu, et al., (2022), CCS is not applied for electricity generation because gas-fired power generation with CCS is too expensive compared to solar and wind energy.

Other low-carbon energy technologies that are used for power generation in modeling studies are geothermal energy (Lombardi et al., 2020), concentrated solar power (CSP) (Gils et al., 2017), and nuclear power (Child et al., 2019). However, new nuclear power plants are not considered because the nuclear power plants in Child et al. (2019) are existing nuclear power plants that have not exceeded their technical lifetime in 2050.

2.1.6. The role of hydrogen in the energy system

Hydrogen technologies can play an important role in decarbonizing the energy system in various ways, but their role differs in the reviewed studies. Some studies do not include hydrogen in the modeling (Bobmann & Staffell, 2015; Child et al., 2019). Hydrogen is included in the PyPSA-Eur model and is used for seasonal storage to balance the variations of wind and solar over several days (Schlachtberger et al., 2017, 2018). An alternative to hydrogen storage in modeling studies is to use synthetic natural gas from the power-to-gas process as a dispatchable resource (Child et al., 2019). In the PyPSA-Eur model, hydrogen is produced domestically via electrolysis and combusted in fuel cells. The hydrogen is stored in above-ground steel tanks (Schlachtberger et al., 2017, p.5). Gea-Bermúdez et al., (2021) model the hydrogen sector in a similar way. In the sector-integrated model PyPSA-Eur-Sec-30, synthetic methane can be produced from hydrogen using the Sabatier process (Brown et al., 2018).

Furthermore, Martínez-Gordón et al. (2022) include the possibility of producing hydrogen with alkaline electrolyzers, consuming hydrogen via solid-oxide fuel cells, or using hydrogen as input to generate synthetic natural gas. Hydrogen is stored in long-term steel tanks, and hydrogen imports are also allowed. It was demonstrated that hydrogen use multiplies when hydrogen imports are inexpensive[6]. If hydrogen imports are cheap, domestic hydrogen production is negligible, and hydrogen is also used for heating in industry.

According to Scheepers, Palacios, Jegu, et al., (2022), hydrogen will become an important energy carrier in the Dutch energy system. In this study, hydrogen is primarily used in industry and transportation, and salt caverns are used to store the hydrogen. At low hydrogen prices, hydrogen is also used in the energy sector and for heating in the built environment (Scheepers, Palacios, Jegu, et al., 2022, p.7). Domestic hydrogen production competes with international hydrogen market prices, and hydrogen is imported when market prices are below 2.7 EUR/kg. Hydrogen is exported if international market prices exceed these levels. Similarly, Martínez-Gordón et al. (2022) found that the installed capacity of offshore wind in the Netherlands is correlated with the international hydrogen market prices[7].

2.1.7. Estimations of offshore wind capacity in the North Sea

Many of the reviewed articles in section 2.1 estimated the total wind power capacity in the North Sea. Neumann & Brown (2021) showed that in the optimal solution with a 100% CO_2 emission reduction, 24% of the electricity is generated by onshore wind power, 55% by offshore wind power, 5% by hydroelectric power, and 16% by solar power. It was found that a cost increase of 4% enables abstaining from onshore wind power entirely and a cost increase of 7.5% enables a renewable energy system without offshore wind power. Further, a 10% more expensive system can function without solar power.

Schlachtberger et al. (2017) estimated that renewable energy generation is dominated by onshore wind energy (59%) instead of offshore wind energy (9%) in the cost-optimal grid scenario. Different cost assumptions of onshore and offshore wind can explain the variation in modeling outcomes. Moreover, Child et al. (2019) have more solar energy (46%) than wind energy (29%) in the electricity mix because cost assumptions for 2050 are used, and the costs of solar PV decrease faster than the costs of wind energy. Gils et al. (2017) found that onshore wind potentials in coastal regions were exploited first, and, as a result, wind turbines were installed mostly onshore. Capacity limits for intermittent renewable energy capacities in the Benelux were also given. The capacity limit for solar PV, onshore wind power, and offshore wind power in the Benelux is 561 GW, 9 GW, and 97 GW, respectively (Gils et al. 2017, p.15).

Some studies also provide offshore wind capacity estimations for the Netherlands. Scheepers, Palacios, Jegu, et al. (2022) estimated that the offshore wind potential in the Netherlands will range from 40 GW to 60 GW in 2050. By then, more than 99% of electricity will be generated by solar panels and wind turbines. Moreover, Martínez-Gordón et al. (2022) estimated that the installed capacities of onshore wind range from 337 GW to 1128 GW, and the installed capacities of solar PV range from 1005 GW to 1807 GW scenario. Offshore wind power plays a smaller role, and the deployment ranges from 37 GW to 237 GW. The

[6] Hydrogen imports account for 98% of all consumed hydrogen when hydrogen import prices are 1.2 EUR/kg. The share of hydrogen imports in total hydrogen consumption decreases to 60% if hydrogen import prices decrease to 3.6 EUR/kg. From 4.8 EUR/kg, hydrogen imports are no longer dominant (17% of the total use).

[7] Offshore wind capacity in the Netherlands is 8.6 GW in the reference scenario when hydrogen import prices are 1.2 EUR/kg and 47.4 GW when hydrogen import prices are 4.8 EUR/kg or higher.

installed capacity of offshore wind in the Netherlands ranges from 6.0 GW in the LVRES scenario to 86.8 GW in the HVRES and LONSH scenarios. Lastly, it was found that allowing offshore interconnectors permits the integration of larger amounts of offshore wind capacity compared to the reference scenarios while increasing the cross-border interconnection capacities.

2.2. Knowledge gaps

From the energy system modeling studies that were analyzed, the following knowledge gaps could be identified:

1. *Incomplete knowledge of system effects on future offshore wind demand in the Netherlands*

Several system effects have already been identified, such as the effect of substituting renewable energy technologies and the effect of transmission expansion on the deployment of offshore wind power in the system. The effect of hydrogen import and transmission expansion on offshore wind power deployment has also been reported. However, these effects are mainly reported for the total system, and these system effects on offshore wind deployment per country are often missing. As a result, research focusing on moderating effects, such as electricity trade with neighboring countries and energy storage, remains relatively underdeveloped.

2. *Effect of growing electricity demand on offshore wind deployment*

Electricity demand is often considered an exogenous variable. The effect of growing electricity demand in the Netherlands and in neighboring countries on offshore wind power deployment has not been investigated thoroughly. For instance, growing electricity demand in Belgium and Germany can lead to a higher demand for offshore wind power in the Netherlands.

3. *Effect of nuclear power on offshore wind deployment*

New nuclear power plants are not considered in the reviewed modeling studies. Nevertheless, the Netherlands is planning to build new nuclear power plants which can compete with offshore wind energy due to the low marginal costs of nuclear power.

4. *Drivers of electricity demand growth in the Netherlands*

The evolution of the electricity demand in the Netherlands is only discussed in one reviewed study that focuses specifically on the Netherlands. Dutch electricity demand is expected to grow, but the contribution of individual technologies, such as heat pumps and electric vehicles, has not been investigated in detail. Hence, it is unknown to what extent new technologies will drive electricity demand in the Netherlands.

5. *Effect of hydrogen demand on the offshore wind deployment*

Hydrogen can be used to couple the energy-intensive industry, transportation, and heating sectors to the electricity sector. Sector coupling increases flexibility, and renewable energy integration and offshore wind farms can become production hubs for green hydrogen from wind energy and desalinated seawater. Subsequently, this will increase electricity demand and flatten the load duration curve since green hydrogen will be produced when the renewable energy supply is high. To the best of the author's knowledge, it has not been examined how different levels of sector integration influence offshore wind demand in the Netherlands.

This thesis aims to answer the identified knowledge gaps 1, 2, 3, and 4. The fifth knowledge gap is only partially covered because the electric power system is modeled. In contrast, other sectors are not coupled to the electric power system in the modeling. The extent to which the research gaps are covered is discussed in chapter 7.

3. Research methodology

This chapter presents the methods used in this thesis. The chapter comprises six sections describing the methodology to answer the research questions formulated in section 1.4. Section 3.1 describes the methodology of the scenario analysis. Section 3.2 selects a modeling tool for the power system modeling. Section 3.3 discusses the data inputs and methods to model the electricity system of the North Sea countries. Further, section 3.4 reports the model validation methods. Subsequently, section 3.5 presents the methodology for conducting the modeling experiments. Finally, the methods for data analysis are explained in section 3.6.

3.1. Analysis energy scenarios studies for the Netherlands

The first research sub-question examines the future electricity demand and renewable energy production in the Netherlands in a decarbonized energy system. Desk research will be used as a research method for this analysis.

Final electricity demand in the Netherlands influences offshore wind capacity demand because the technical potential of alternative renewable energy technologies, such as onshore wind and solar PV, is limited. Moreover, electricity demand is likely to increase in the Netherlands due to population growth, the electrification of heating, industry, transportation, and the production of e-fuels. Heat pumps can be used in the built environment, electric vehicles (EVs) can be used in transportation, and industrial processes can be electrified. Electricity can also be used to produce sustainable fuels such as hydrogen via hydrolysis. The future electricity demand can be calculated using the following equation:

$$E_{demand} = E_{existing\_applications} + E_{EVs} + E_{heat\_pumps} + E_{electrification\_industry} + E_{molecules} \qquad (1)$$

Here, the term $E_{existing\_applications}$ denotes the aggregated electricity use of all current applications of electricity in all sectors. The term $E_{molecules}$ denotes (green) hydrogen produced via electrolysis and synthetic fuels. First, the estimated electricity demand in each scenario study in the Netherlands aggregated by sector will be compared. These scenarios studies will also be compared to energy scenarios studies with a European scope. After that, the differences in electricity demand per sector will be examined, and the role of EVs, heat pumps, electrification of industrial processes, and production of green molecules will be quantified.

Furthermore, on the supply side of electricity, the estimations of future capacities of renewable energy sources are being investigated. These renewable energy technologies are offshore and onshore wind power, solar power, nuclear power, and other renewable energy sources such as biomass and (green) hydrogen. Hence, the future renewable electricity supply in a decarbonized energy system is the sum of all renewable electricity generation. This leads to the following equation:

$$E_{supply} = E_{offshore\ wind} + E_{solar} + E_{onshore\ wind} + E_{nuclear} + E_{other} \qquad (2)$$

Lastly, the capacity factors of renewable energy technologies used in the different scenario studies are compared to each other.

3.2. Selection of the modeling tool

This section discusses which model is used to model the system effects of integrating many wind turbines in the Dutch energy system in 2040. Historically, energy system modeling was proprietary and not shared with other parties. These models' lack of transparency and reproducibility has been criticized in the past (Pfenninger et al., 2014). This has changed in recent years, and available open-source tools are mature enough compared to commercial or proprietary tools of use (Groissböck, 2019). It is chosen to use an existing model because the use of an existing model enhances the reliability of the modeling results. The strengths and limitations of peer-reviewed energy system models are known and documented, which is not the case when a model is built from scratch. Moreover, developing an energy system model is a complicated task, and the identified research gaps in section 2.2 are not related to shortcomings in existing energy system models.

There are various open-source energy models available, and seventeen models are considered. An overview of the considered models can be found in Table 34 of Appendix A. The considered models are reviewed by (Oberle & Elsland, 2019) and (Groissböck, 2019), and the selection criteria mentioned in these review articles are used to select the model for this research. Even though the used literature reviews stem from 2019, these models are still the most recent literature reviews focused on power system models, according to a meta-review by Chang et al., (2021). The models are selected based on the five criteria described in Table 2. Eight models fulfill the five selection criteria. These models are Calliope, Ficus, NEMO, OSeMOSYS, Pypsa, Switch, TEMOA, and urbs.

Table 2: overview of selection criteria for modeling tool selection.

Criteria	Description
Criterium 1: level of accessibility	Open-access models are preferred that can be operated without external commercial software. This means that all models written in GAMS and MATLAB are excluded. Furthermore, the models that require a license will be excluded. Models that can be operated using an open-source and commercial solver are considered.
Criterium 2: spatial granularity	It is chosen to use a model that can be used for multiple countries because the optimization question considers the electricity system of the North Sea countries. Models that weigh only a single country or region are excluded.
Criterium 3: sectoral coverage	The model should include the electricity sector, which means that models that do not include the electricity sector are excluded.
Criterium 4: temporal granularity	Regarding the temporal granularity, only a single year will be considered. This is because the power system in 2040 will be modeled, and energy transition pathways are not part of the research questions. Furthermore, the model should consider hourly time steps because the electricity generation of renewable energy technologies such as solar and wind differs during the day and the year.
Criterium 5 analytical approach	The second research sub-question is an optimization question. This implies that top-down models, accounting models, and simulation models do not satisfy.

Groissböck (2019) evaluated 31 energy modeling tools based on 81 proposed modeling details. Switch, TEMOA OSeMOSYS, and PyPSA were considered the top-performing open-source models. PyPSA is the preferred modeling tool for this research because it performed better within the operational assessment than the commercial closed source tools (Groissböck, 2019, p.246), and most of the reviewed studies in chapter 2 that modeled the European power system used PyPSA.

3.3. Model formalization

The power system model PyPSA-Eur is used in this research. PyPSA-Eur is an open model dataset of the European power system at the transmission network level that covers the entire ENTSO-E area (Hörsch, Hofmann, et al., 2018). It can be imported into the open toolbox PyPSA, which is an acronym for 'Python for Power System Analysis'. The dataset consists of a grid model that contains 3642 substations and 6763 lines, which are 13 alternating current lines at and above 22 kV voltage level and all high voltage direct current (HVDC) lines. Furthermore, the open power plant database powerplantmatching is included in PyPSA-Eur. Powerplantmatching is a toolset for cleaning, standardizing, and combining multiple power plant databases. The renewable time series are based on ERA5 and SARAH, and assembled using the Atlite tool. The geographical potentials for wind and solar generators are based on land use (CORINE), excluding the Natura 2000 zones. The computation is done with the Atlite library.

The PyPSA-EUR repository is cloned using the version control system Git[8]. The PyPSA-Eur version on Github of July 17, 2022, is cloned. The model is applied to a stylized setting for 100% CO_2 reduction scenarios. The first step is to reduce the size of the electricity system such that only the North Sea countries are included in the model. After that, a selection of existing and expandable power plants are made. Then, the cost and technologies assumptions for electricity generation technologies, electricity storage, and infrastructure components are defined. After that, the electric load is given as input to the model, and constraints are formulated.

The optimizations problems were solved on a Windows 10 notebook computer with a 10th-generation Intel Core i5 Mobile processor and 16 GB RAM. When the model has been formalized, PyPSA passes the PyPSA-Eur network model to an external solver that performs a total annual system cost minimization with optimal power flow. For the optimization, the commercial solver Gurobi v.9.5.2 is used via the barrier method under an academic license. However, it was not possible to run the model on the highest resolution due to hardware constraints. The number of nodes in the power system network was simplified in order to reduce the size of the linear programming problem using the k-means clustering method as presented by (Hörsch & Brown, 2017). The model's temporal complexity is also reduced to simplify the problem.

3.4. Model validation

Model validation is a critical step in the modeling lifecycle. Model validation refers to determining the degree to which a model accurately represents its intended purpose (Allen et al., 2010). The PyPSA-Eur model has also been validated by Unnewehr et al., (2022), and it was found that the model captured the main power system characteristics for Germany and neighboring countries.

The model validation is carried out in tandem with the model development process. First, the model is run with limited spatial and temporal resolution and few constraints to check if it behaves as it intends to. After that, the complexity of the model is expanded by adding more components to the model. The assumptions in the model are validated by checking the reliability and actuality of the data sources. The model validation is done by examining the model output for reasonableness such that extreme or unlikely outcomes are avoided. In addition, the model outcomes are validated by the energy experts of the consultancy firm Common Futures.

[8] Git is a distributed version control system that tracks changes in a set of files. Git is used for coordinating work among programmers collaboratively.

3.5. Experimentation

The workflow management system Snakemake controls the generation of the model. Experiments are conducted using the power system model, and the network model is optimized for a single year. The network model co-optimizes generation, network, and storage capacities to find the lowest system costs. The focus is on the lowest societal costs because the discussion of economic equality or equity is easier when the costs of electricity generation are optimized[9].

In the experiments, different constraints are modified, and the effect on the optimal generation, network, and storage capacities is examined. A baseline scenario and 24 scenarios are formulated based on the outcomes of the scenario analysis. In each of the 24 scenarios, one parameter is changed relative to the baseline scenario. The experiments aim to gain insights into the factors influencing optimized offshore wind power capacities. In the scenarios, the electrical load, the technology costs, the set of extendable generators in the model, the generator capacity limit, the transmission line expansion limit, and the minimal domestic production requirement are changed. Moreover, a sensitivity analysis is performed, which provides insights into the model's limitations.

3.6 Data analysis and results validation

The main results obtained from the optimization are generation and storage capacities, power generated per renewable energy technology, charge and discharge of storage, power flows, marginal prices, and transmission line capacities. The results are analyzed in Jupyter Notebook using the programming language Python. The model is stored in the network component, which is a container for all components and functions that act upon the whole network. For each class of components, the data that describes the component is stored in a Pandas DataFrame. Furthermore, the results are validated by comparing the modeling outcomes to scientific sources.

[9] Other concerns are, for instance, public support and security of supply. Chapter 7 elaborates on these issues.

4. Scenario analysis

The results of the scenario analysis are presented in this chapter. First, section 4.1 makes a selection of energy scenario studies that estimate future electricity demand and supply in the Netherlands. Section 4.2 presents electricity use aggregated by sector. Section 4.3 compares energy scenario studies with a Dutch scope to scenario studies with a European scope. After that, sections 4.4 to section 4.7 elaborate on the role of electric vehicles, heat pumps in the built environment, electrification of industry, and the production of sustainable molecules such as green hydrogen on future electricity demand in the Netherlands. Further, sections 4.8 and 4.9 investigate estimations of future electricity supply in the Netherlands. Section 4.10 discusses the correlation between offshore wind capacity, electricity demand, and green hydrogen production in the Netherlands. Finally, the conclusions of the scenario analysis are presented in section 4.11. An extensive overview of the references used in this chapter is shown in Table 41 of Appendix I.

4.1. Selection of decarbonized energy scenarios studies for the Netherlands

Different scenario studies have examined future energy systems that are compatible with the Paris agreement. These studies are made on different levels of aggregation. The IPCC has carried out a comprehensive assessment of global scenarios compatible with 1.5 °C global warming (Intergovernmental Panel on Climate Change, 2018), the European Commission published an extended scenario analysis with a focus on the EU (European Commission, 2018), and assessments have been made with a national scope (Scheepers, Palacios, Janssen, et al., 2022).

Only studies focusing on the Netherlands or the European Union are included in this analysis. The selected studies assume net zero emissions in 2050 or are aligned with the carbon emission reduction goals of the European Union in 2030. In addition, studies before 2018 are not considered because future cost assumptions for renewable energy were too conservative in the past (Tidball et al., 2010). The selection of studies is presented in Table 3, and most known studies are included in the analysis[10]. A short description of each scenario study is given in the following paragraphs.

Table 3: overview of the selected energy scenario studies.

Title study	Temporal scope	Modeling tool	Geographical scope	Reference
Klimaat en Energieverkenning 2021 (KEV 2021)	2030	KEV model	The Netherlands	(PBL, 2021)
Integrale Infrastructuurverkenning 2030-2050 (II3050)	2050	Energy transition model (ETM)	The Netherlands	(Netbeheer Nederland, 2021)
Towards a sustainable energy system for the Netherlands in 2050 - Scenario update and analysis of heat supply and chemical and fuel production	2050	OPERA	The Netherlands	(Scheepers, Palacios, Janssen, et al., 2022)

[10] Stichting Urgenda, a non-profit foundation that aims to make the Netherlands more sustainable, also presented its vision for a decarbonized energy system of the Netherlands with 40 GW offshore wind capacity in 2030 (Urgenda, 2019). However, the evolution of electricity demand is not discussed in detail, and this study is therefore not included in the analysis.

from sustainable feedstocks (TNO 2022)				
Design of a Dutch carbon-free energy system EnergyNL2050 (KIVI 2020)	2050	Own model	The Netherlands	(Persoon et al., 2020)
Alles uit de kast – Een verkenning naar de opgaven voor het Nederlandse elektriciteitssyteem van 2030 (Werkgroep Extra Opgave 2020)	2030	COMPETES[11]	The Netherlands	(Werkgroep Extra Opgave, 2022)
EU: fit for 55 scenarios	2030	Primes	European Union	(Directorate-General for Energy, 2021a, 2021b, 2021c)
TYNDP 2022 Scenario Report (TYNDP 2022)	2050	Own model	European Union	(ENTSOG & ENTSO-E, 2022d)
A Clean Planet for All – A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy	2050	PRIMES-GAINS-GLOBIOM	European Union	(European Commission, 2018)

The Klimaat- en Energieverkenning (KEV 2021) outlines the development of the Dutch energy system in the past, present, and future. In addition, the KEV 2021 discusses the contribution of climate policy in the Netherlands to the development of the Dutch energy system (PBL, 2021).

The Integrale Infrastruurverkenning 2030-2050 (II3050) aims to gain insights into energy infrastructure and system integration needed for a climate-neutral energy system in 2050. The study consists of four scenarios: Regional Steering, National Steering, European Steering, and International Steering[12]. These four scenarios are chosen to show different energy transition pathways. Some scenarios assume that the Netherlands becomes self-sufficient in its energy supply, while others rely more on energy imports. Moreover, the role of the energy-intensive industry differs in these scenarios; some scenarios assume a contraction of the energy-intensive industry, whereas other scenarios assume significant growth of the energy-intensive industry (Netbeheer Nederland, 2021).

TNO has also examined the development of the Dutch energy system, and two energy scenarios have been developed: ADAPT and TRANSFORM. In the ADAPT scenario, the current lifestyle of the Dutch population is preserved, and the Dutch economy is built on existing infrastructure while reducing CO_2 emissions significantly. In the TRANSFORM scenario, behavioral changes are made in Dutch society, and a significant shift towards a more sustainable economy is made. As a result, the Dutch economy will become less energy-intensive (Scheepers, Palacios, Janssen, et al., 2022).

The fourth study that is analyzed is a study conducted by the Koninklijk Instituut Van Ingenieurs (KIVI 2020). This study describes an energy system that generates more than 85% of the nationally needed energy and imports at most 15% of its energy from abroad. The plan is based on the views of more than fifty Dutch professionals on the Dutch energy transition challenge (Persoon et al., 2020).

At the time of the climate agreement in 2018, it was assumed that electricity demand would be approximately 120 TWh in 2030 without additional climate policy. The Werkgroep Extra Opgave has been instructed to analyze the additional electricity demand necessary to achieve the target for reducing emissions

[11] TNO conducted the modeling analysis.

[12] The scenarios' names are translated from Dutch.

of the Dutch climate agreement (Werkgroep Extra Opgave, 2022). Three scenarios are developed, and each has its own reduction goal: 'the 49% reduction scenario', the '55% reduction scenario', and 'the 55% reduction + REDIII scenario'. In the '55% reduction + REDIII scenario', the electricity demand that is compatible with the Renewable Energy Directive (REDIII) and a 55% reduction in greenhouse gas emissions is estimated. The REDIII requires that 50% of the hydrogen used in industry is produced with renewable energy. Furthermore, 2.6% of the energy use in the mobility sector must consist of Renewable Fuels of Non-Biological Origins (Hers et al., 2022, p.5).

The analysis also includes three energy scenarios focusing on the European Union. The TYNDP 2022 is a joint scenario report from the ENTSO-E and the ENTSOG[13], which consists of the Global Ambition and Distributed Energy scenarios using a top-down approach with a full-energy perspective. Both scenarios are in line with the 1.5 °C targets of the Paris Agreement (ENTSOG & ENTSO-E, 2022d). The Distributed Ambition scenario is driven by a willingness of society to achieve energy autonomy based on indigenous renewable energy sources. The Global Ambition scenario relies on centralized renewable and low-carbon technologies and the use of global energy trade to accelerate decarbonization.

The European Commission published in 2018 a long-term strategy called 'A Clean Planet for All', which aims to achieve climate neutrality in 2050. An extensive scenario analysis with a variety of scenarios is presented as part of the communication. Five scenarios achieve an 80% CO_2 emission reduction, and two achieve net zero in 2050[14] (European Commission, 2018, p.56).

Further, the European Commission published three scenarios to analyze various initiatives of the European Green Deal policy in 2021. These scenarios are used as tools for analysis. The REG scenario relies on a strong intensification of energy and transport policies, the MIX-CP scenario relies on carbon price-driven policies, and the MIX scenario relies on both carbon price-driven and energy and transport policies (European Commission, 2021).

4.2. Estimations of future electricity use in the Netherlands aggregated by sector

Electricity use is often categorized by the following sectors: the built environment, agriculture, transportation, and industry. The aggregated electricity use in different scenarios is analyzed solely focusing on the Netherlands. These studies are the II3050, the KEV 2021, TNO 2022, and KIVI 2020 (see the previous section for a description). The TYNDP 2022 study for the Netherlands is omitted because the TYNDP uses different demand categorizations[15]. The results of the analysis are shown in Table 4. It can be seen that the electricity demand estimations in the Netherlands range from 125 TWh to 206 TWh in 2030 and from 243 TWh to 544 TWh in 2050.

Electricity use in the built environment without heating will increase from 50 TWh to 55 TWh in 2030 and from 59 to 67 TWh in 2050. The electricity consumption in the built environment in 2050 shows an outlier of 127 TWh in the KIVI 2020. This outlier includes electricity use in the agricultural and industrial sectors and can, therefore, not be compared to other studies. Without the outlier, it is expected that electricity use in applications such as illumination, cooking, and home appliances will remain relatively flat in the future. Part

[13] The ENTSO-E represents the electricity transmission system operators in the EU, and the ENTSOG represents the gas transmission system operators in the EU.

[14] The scenarios studies that achieve net zero in 2050 are '1.5Tech' and '1.5LIFE', and these scenarios are included in the analysis.

[15] The electricity demand categories of the TYNDP 2022 are heating & cooling, non-energy use, transport, electrical appliances, cooking, energy branch, and other demand.

of the extra electricity in the built environment can be attributed to data centers[16] in some studies (Netbeheer Nederland, 2021, p.48; Werkgroep Extra Opgave, 2022, p.6), or extra electricity demand in the service sector[17] (Scheepers, Palacios, Janssen, et al., 2022, p.21).

Electricity demand estimations for heating in the built environment range from 5 to 14 TWh in 2030 and from 16 to 29 TWh in 2050. The difference can be explained by the number of heat pumps and the isolation level in the built environment.

Electricity use in agriculture ranges from 11 to 13 TWh in 2030 and ranges from 12 TWh to 25 TWh in 2050, up from 9 TWh in 2015. Most of the electricity consumption in agriculture is used in greenhouses[18]. According to the KEV 2021, the increase in electricity use in agriculture is mainly caused by a further intensification of illumination in greenhouses (PBL, 2021, p.159). The II3050 estimates that the electricity use in agriculture will increase to 25 TWh in 2050 in all scenarios due to strong electrification (Netbeheer Nederland, 2021, p.29). However, it is not explained what causes the higher electricity demand in agriculture in 2050, and electricity use for heating makes up only a small part of electricity demand according to the ETM model (Quintel Intelligence, 2022). Hence, the difference in electricity use in the agricultural sector may be smaller than presented[19].

The electricity demand in transportation ranges from 7 to 16 TWh in 2030, and electricity demand in transportation ranges from 12 TWh to 25 TWh in 2050. These changes can be explained by the phasing-out of internal combustion engines (ICE) and the adoption of electric vehicles (EV). Changes in transportation behavior can also explain part of the changes.

Energetic electricity use in the industry is estimated to be between 50 TWh and 71 TWh in 2030. For 2050, the industry's expected electricity demand ranges from 69 TWh to 118 TWh. The projected electricity use in the industry differs due to the different roles of hydrogen and biomass in the energy supply of the industry. Moreover, the size of the energy-intensive industry plays a role in the scenarios of the II3050 and TNO 2022 (Netbeheer Nederland, 2021, p.25-29; Scheepers, Palacios, Janssen, et al., 2022, p.47-48).

Lastly, electricity demand for the production of green hydrogen is expected to play a role. A wide disparity can be observed between the scenarios and the electricity demand. The electricity demand estimations for green hydrogen production range from 0 TWh to 39 TWh in 2030 and from 0 TWh to 292 TWh in 2050. Green hydrogen can be used as an energy carrier for applications in heating in the built environment and industry, as fuel in transportation, and green hydrogen can be used as feedstock.

In conclusion, the largest differences in electricity demand estimations are caused by uncertainties about the role of hydrogen in the future, followed by electricity demand in the industry. Electricity demand in the built environment remains relatively flat when heating is not included. Furthermore, differences in electricity demand for heating in the built environment, agriculture, and transportation are relatively modest.

[16] Werkgroep extra opgave estimated that electricity demand by data centers will increase by 2.3 TWh in 2030, and the II3050 estimated that data centers will consume 2 TWh more in 2050 compared to today.

[17] Electricity use in the service sector in TNO 2020 is 44.3 TWh in TRANSFORM and 38.4 TWh in ADAPT.

[18] Werkgroep Extra Opgave estimated that 2 TWh extra electricity demand in greenhouses is needed in 2030 and 4 TWh extra is needed in 2040 relative to 2015 (Hers et al., 2022, p.20).

[19] According to TNO 2022, Electricity demand in agriculture ranges from 12 TWh in ADAPT to 18 TWh in TRANSFORM. However, the reason why electricity demand differs between the scenarios is not discussed (Scheepers, Palacios, Janssen, et al., 2022, p.74).

Table 4: overview of electricity use in different scenario studies aggregated by sector. Electricity use for international transport and distribution and conversion losses are not taken into account.

Name study	Name scenario	Scenario year	Total electricity demand [TWh]	1. Electricity use In the Built environment excluding heating [TWh]	2. Electricity use for Heating in the built environment [TWh]	3. Electricity use in agriculture [TWh]	4. Electricity use in transportation [TWh]	5. Electricity use in Industry [TWh]	6. Electricity use for hydrogen production [TWh][20]
KEV 2021	Reference	2015	109	54	3	9	2	42	0
	Projection	2030	125	50	5	13	7	50	0
Werkgroep Extra Opgave[21]	49% CO_2 reduction	2030	164	55	12	11	14	64	8
	55% CO_2 reduction	2030	188	55	14	11	16	71	21
	55% CO_2 reduction + REDIII	2030	206	55	14	11	16	71	39
KIVI 2020		2050	386	127[22]	25	-	28	26[23]	175
II3050	Regional Steering	2050	243	66	16	25	30	76	29
	National Steering	2050	297	66	23	25	28	103	52
	European Steering	2050	275	67	21	25	33	117	12
	International Steering	2050	258	66	22	25	28	118	0
TNO 2022	ADAPT	2050	314	59[24]	21	12	28	69	101
	TRANSFORM	2050	544	67[8]	29	18	20	116	292

[20] Electricity used to produce green hydrogen. This number differs from the energy content of hydrogen because the efficiency to transform electricity to hydrogen is around 80% when teh higher heating value is used (National Renewable Energy Laboratory (NREL), 2009). The Werkgroep Extra Opgave used the lower heating value for their calculation, which is 57% (Werkgroep Extra Opgave, 2022, p.3).

[21] The electricity demand in Werkgroep Extra Opgave, 2022 is displayed as extra electricity demand in 2030 relative to the electricity demand in 2019 when the Dutch climate agreement was signed (Rijksoverheid, 2019).

[22] This electricity demand in the built environment is the sum of 'basic demand + air-conditioning and electricity demand used for heating. This number is relatively high because there is no distinction made between sectors, so basic demand in agriculture and industry is included.

[23] Part of the electricity demand used in industry is included in 'electricity use in the built environment.

[24] Electricity use in the built environment in TNO 2022 is calculated by summation of the electricity use of services and households.

4.3. Comparison final energy consumption by carrier

In this section, the Dutch energy scenarios of section 4.2 are compared to studies with a European focus. The studies with a European focus are A Clean Planet for All, Fit for 55, and the TYNDP 2022. These studies do not elaborate on the electricity demand per sector and are therefore not included in Table 4. In order to examine the differences between scenario studies with a European scope and studies with a Dutch scope, final energy consumption by energy carrier is compared instead of electricity. The results of the analysis are shown in Table 5.

Table 5: net-zero energy scenarios for the Netherlands compared to net-zero energy scenarios that focus on the European Union. Energy use for international transport is not included.

Name study	Name scenario	Scenario year	Final energy consumption [TWh]	Electricity use excluding hydrogen and e-fuels production as percentage of final energy demand [%]	Electricity use for hydrogen and e-fuel production as percentage of final energy demand [%]
European scenarios					
A Clean Planet for All	Reference	2015	12793	21%	0%
	1.5TECH	2050	8025	51%	25%
	1.5LIFE	2050	7211	50%	22%
TYNDP 2022 Europe	Distributed energy	2050	8660	46%	17%
	Global Ambition	2050	9409	38%	16%
Scenarios for the Netherlands					
KEV 2021	Reference	2015	645[25]	17%	0%
KIVI 2020		2050	486[26]	43%	26%
II3050	Regional Steering	2050	441	49%	13%
	National Steering	2050	526	47%	19%
	European Steering	2050	713	37%	3%
	International Steering	2050	736	35%	0%
TNO 2022	ADAPT	2050	619	34%	17%
	TRANSFORM	2050	523	48%	56%[27]
European green deal: fit for 55	Reference	2015	622	17%	0%
	REG scenario	2030	544	24%	0%
	MIX scenario	2030	556	24%	0%
	MIX-CP scenario	2030	556	24%	0%

First, it can be observed that electricity demand as a share of final energy demand is around 50% in the 1.5TECH and 1.5LIFE scenarios of A Clean Planet for All. The share of hydrogen and e-fuels as a percentage of final energy consumption is 25% in 1.5TECH and 22% in 1.5LIFE. Furthermore, final energy consumption decreases sharply in the 1.5TECH and 1.5LIFE scenarios. The share of electricity as part of final energy consumption is lower in the Distributed Energy and Global Ambition scenarios of the TYNDP 2022. These scenarios rely more on biomass and sustainable fuel imports than the scenarios of A Clean Planet for All. In addition, the scenarios of the TYNDP 2022 focus less on energy savings than the scenarios of A Clean Planet for all.

[25] The non-energetic energy use is on average 500 PJ and this is added to the final energetic energy use, which was 1821 PJ in 2015.

[26] The electricity use is 386 TWh, the non-energetic energy use is 80 TWh and the energy use for heat is 20 TWh. Hence, the final energy use is 486 TWh.

[27] Part of the hydrogen is used in this study to produce e-fuels for international transport. However, international transport is omitted in several analyses because it is not part of the Paris Agreement.

When the studies with a European scope are compared to the studies with a Dutch scope, the European Steering and International Steering scenarios of the II3050 stand out because final energy consumption increase in the European Steering and International Steering scenarios, whereas final energy consumption decrease in the studies with a European scope. In addition, the share of electricity use for hydrogen and e-fuels production in these studies is low compared to the studies with a European scope.

In the scenarios of Fit for 55, it can be observed that final energy use decreases by 10% in the Netherlands, compared to a modest decrease of 4% in the KEV 2021. In addition, the electrification of the economy in the European scenarios is higher than in the KEV 2021. The Werkgroep Extra Opgave addressed this issue and advised to make extra investments in the electricity system of the Netherlands (Werkgroep Extra Opgave, 2022, p.4-5). Furthermore, hydrogen will play a minor role as a non-energetic energy carrier in the energy system of the Netherlands in 2030, according to the KEV 2021. This is also the case in the scenarios of the Fit for 55.

4.4. The role of e-mobility in future electricity demand

Electric vehicles are expected to increase electricity demand in the future This section investigates how much of the extra electricity demand in the future can be attributed to more electric vehicles. The electricity demand estimations in the mobility sector are shown in Table 6. When electricity is not used as an energy carrier, hydrogen is often used as an energy carrier in transportation, followed by biofuels in a decarbonized energy system.

Table 6: overview of the estimated number of electric vehicles in the Netherlands and its effect on future electricity demand.

Name study	Name scenario	Scenario year	Electricity use mobility (TWh)	Percentage electric cars [%]	Percentage electric LDV [%]	Percentage electric HDV [%]	Vehicle kilometers [billion]
KEV 2021	Reference	2019	3	2%	2%	0%	142
		2030	7	11%	10%	5%	153
Werkgroep Extra Opgave	49% CO_2 reduction	2030	14	-	-	-	-
	55% CO_2 reduction	2030	17	-	-	-	-
	55% CO_2 reduction + REDIII	2030	17	-	-	-	-
KIVI 2020		2050	28	100%	0%	0%	-
II3050	Regional Steering	2050	30	100%	75%	75%	88
	National Steering	2050	28	95%	25%	25%	144
	European Steering	2050	33	70%	25%	25%	203
	International Steering	2050	29	50%	25%	25%	203
TNO 2022	ADAPT	2050	28	100%	100%	0%	182
	TRANSFORM	2050	20	100%	100%	0%	117

The KEV 2021 estimated that 7 TWh will be used for mobility in 2030. According to the KEV 2021, there will be 1.1 million electric cars, 100.000 light-duty electric vehicles (LDV), and 13.000 electric high-duty vehicles (HDV) on the road (PBL, 2021, p.175-176). Part of the increase in electricity demand in the mobility sector is attributed to the electrification of public transport and the electrification of other transportation modes. Trains will consume more electricity in 2030, and 95% of the buses will be electric. In addition, a third of the bikes will be electric in 2030. The extra electricity consumption attributed to the adoption of electric cars, LDV, and HDV in the KEV 2021 is 3 TWh. The Werkgroep Extra Opgave does not specify the number of electric vehicles but reports only the extra electricity consumption necessary to achieve the CO_2 emission reduction targets in its three scenarios. Suppose the numbers of the KEV 2021 are extrapolated. In that case, there will be more than 3 million electric vehicles in the 49% reduction scenario and more than 4 million electric vehicles in the 55% CO2 reduction and 55% CO2 reduction + REDIII scenarios.

Moreover, the TNO 2022 estimated that the entire passenger car and LDV fleet are electric in both scenarios. This corresponds to 57% (28 TWh) of the total final energy use for domestic transport in the ADAPT scenario and 93% (20 TWh) of the total final energy use for domestic transport in the TRANSFORM scenario (Scheepers et al., 2022, p.55). The HDVs are fueled by hydrogen in the TNO 2022 scenarios. The number of kilometers can explain the difference in electricity use between the ADAPT and TRANSFORM scenarios[28]. Suppose the values for passengers traveling from the KEV 2021 are extrapolated. In that case, there are approximately 7 million electric vehicles in the TRANSFORM scenario and approximately 13 million electric vehicles in the ADAPT scenario [29]. The kilometers traveled by electric LDV are the same in both scenarios and increase by 10% (Scheepers et al., 2022, p.21). This corresponds to 3.3 million electric LDV in both scenarios.

In the II3050, it is assumed that the travel behavior changes. According to the II3050, citizens travel in 2050 70.6% of their kilometers by car, 11% of their travel kilometers by train, and 6.9% of their travel kilometers by bus. In 2019, citizens traveled 74.4% of their kilometers per car, 8.9% of their travel kilometers per train, and 6.1% of their travel kilometers per bus. Furthermore, it is assumed that passenger transport decreases in the Regional Steering scenario. Passenger stays constant in the National Steering scenario and increases in the European Steering and International Steering scenarios. The scenarios also differ in the automotive technologies used; hydrogen and biofuels are used in the II3050 as alternatives to electricity.

4.5. The role of electric heating in future electricity demand

Heat pumps are a promising technique to decarbonize heating in the built environment. In this section, there will be elaborated on how much of the extra electricity demand in the future can be attributed to heat pumps. The electricity demand estimations of heat pumps in the built environment are shown in Table 7.

The KEV 2021 estimates that around 11% of the built environment will be heated using heat pumps in 2030. This corresponds to approximately 900,000 heat pumps with 8.2 million residences in 2030. Moreover, the Werkgroep Extra Opgave estimates that electricity use for heating and cooling will increase by 8.4 TWh to 11.8 TWh in 2030 in the 49% reduction scenario (Hers et al., 2022, p.17). In the 55% reduction scenario and the 55% reduction + REDIII scenario, electricity use for heat pumps will increase by 10.5 TWh to 13,9 TWh in 2030. When extrapolated, this translates to 2.3 million heat pumps in the 49% reduction scenario and 2.7 million heat pumps in the 55% reduction and the 55% reduction + REDIII scenarios.

In the II3050, the percentage of electric heat pumps ranges between 25% in the European Steering and International Steering scenarios and 55% in the National Steering scenario. The percentage of hybrid heat pumps ranges between 20% in the Regional Steering and National Steering scenarios to 60% in the European Steering and International Steering scenarios. Furthermore, it is assumed that the number of residences will increase to 8.8 million in 2050 (Netbeheer Nederland, 2021, p.29). As a result, there will be between 2.2 and 4.8 million electric heat pumps and between 1.8 and 5.3 million hybrid heat pumps in residences in 2050. Differences in energy use in these scenarios are caused by differences in the insulation level of buildings, which is the highest in the National Steering scenario and the lowest in the European Steering scenario.

[28] In the ADAPT scenario, passengers travel 149 billion kilometers via road. In the TRANSFORM scenario, passengers travel 84 billion kilometers via road.

[29] The passenger fleet in 2019 is approximately 10 million cars, and passenger road traffic is 115 billion vehicle kilometers. The ADAPT scenario shows a 30% increase in car use. In TRANSFORM, there is a 27% decrease in car use.

Table 7: overview of the estimated number of heat pumps in the built environment in the Netherlands and its effect on future electricity demand.

Name study	Name scenario	Scenario year	Electricity use for heating in the built environment [TWh]	Percentage electric heat pumps in the built environment [%]	Percentage hybrid heat pumps in built environment [%]	Total heat supply in the built environment [TWh]
KEV 2021	Reference	2019	3	-	-	126
		2030	5	11%	-	111
Werkgroep Extra Opgave	49% CO_2 reduction	2030	12	-	-	-
	55% CO_2 reduction	2030	14	-	-	-
	55% CO_2 reduction + REDIII	2030	14	-	-	-
KIVI 2020		2050	16	83%	-	120
II3050	Regional Steering	2050	16	35%	20%	87
	National Steering	2050	23	55%	20%	68
	European Steering	2050	21	25%	60%	87
	International Steering	2050	22	25%	60%	87
TNO 2022	ADAPT	2050	20	38%	-	92
	TRANSFORM	2050	29	78%	-	90

Lastly, the TNO 2022 estimates that the percentage of heat pumps is 38% in the ADAPT scenario and 78% in the TRANSFORM scenario. These scenarios assume 8 million residences. Hence the number of heat pumps in residences in 2050, according to these scenarios, is between 3 and 6.2 million.

4.6. The role of electrification in the industry in future electricity demand

Electrification in the industry is another important pillar in decarbonizing the Dutch energy system. This section investigates to what extent electrification in the industry will lead to extra electricity demand in 2030 and 2050. The electricity demand in the industry is shown in Table 8.

Table 8: overview of the estimation for electrification in industry and its effect on electricity demand in 2030 and 2050.

Name study	Name scenario	Scenario year	Electricity use in industry [TWh]	Total energy use for heating in industry [TWh]	Electrification in industry [%]
KEV 2021	Reference	2019	43	211	20%
		2030	50	191	26%
Werkgroep Extra Opgave	49% CO_2 reduction	2030	64	-	-
	55% CO_2 reduction	2030	71	-	-
	55% CO_2 reduction + REDIII	2030	71	-	-
II3050	Regional Steering	2050	76	103	74%
	National Steering	2050	103	148	69%
	European Steering	2050	117	231	50%
	International Steering	2050	118	222	53%
TNO 2022	ADAPT	2050	69	148	47%
	TRANSFORM	2050	116	125	93%

First, the KEV 2021 expects that 50 TWh will be used in the industry in 2030. This increases the share of electricity in the total energetic energy use in industry from 20% to 26%. The Werkgroep Extra Opgave estimated that electricity use in the industry will be between 64 TWh and 71 TWh in 2030. Since electrification also leads to energy savings, it is unclear what the share of electricity use will be in the total energy use for heating in industry.

Moreover, the II3050 estimates that electricity use in the industry will range from 76 TWh to 118 TWh in 2050. The share of electricity in total energy use in the industry ranges from 53% to 74%. In the Regional Steering scenario, electricity will make up 74% of the energy use for heating in industry in 2050. In this scenario, large parts of the energy-intensive industries will disappear. Steel, aluminum, paper, and food production will decline by 22%, and the chemical industry will remain roughly the same size. The fertilizer industry and the oil industry will largely disappear in the Netherlands. In the European steering and International Steering scenarios, steel, aluminum, paper, and food production will increase by 45%, and the fertilizer industry will remain the same size. The size of the oil industry decreases by 60% in these scenarios (Quintel Intelligence, 2022).

In the TNO 2022 study, electricity use in industry in 2050 ranges from 69 TWh in the ADAPT scenario to 116 TWh in the TRANSFORM scenario. In addition, electricity makes up between 50% and 74% of total energy use for heating in industry. In the ADAPT scenario, industrial production increases slightly, and industrial production decreases in the TRANSFORM scenario[30] (Scheepers et al., 2022, p.21). The difference in industrial production between the ADAPT and TRANSFORM scenarios is smaller than the difference in industrial output between the scenarios in the II3050.

4.7. Estimations of future hydrogen use in the Netherlands aggregated by sector

In this section, hydrogen use in different scenarios is compared. As a result, the potential for sector coupling via hydrogen can be determined. This affects electricity demand when green hydrogen is produced domestically. There are also other methods to produce low-carbon hydrogen, such as steam-reforming methane with CCS. Another option is (green) hydrogen import. An overview of hydrogen use in different sectors is shown in Table 9.

Hydrogen can be used as a fuel in boilers for heating in the built environment as an alternative to methane. This form of heating plays a role in the European Steering and International Steering scenarios in the II3050. Moreover, hydrogen consumption for heating plays a role in the ADAPT scenario of TNO 2022. However, it plays only a minor role in the TRANSFORM scenario.

Hydrogen use in mobility ranges from 0 TWh to 8 TWh in 2030 and ranges from 3 TWh to 44 TWh in 2050. In the Werkgroep Extra Opgave, hydrogen is only used in mobility in the 55% reduction + REDIII scenario[31]. The KIVI 2020 has the largest hydrogen share in mobility because all LDVs and HDVs are fueled with hydrogen. Hydrogen is only used to fuel HDV in TNO 2022 (Scheepers et al., 2022, p.54-55). The II3050 assumes that the hydrogen use in mobility is 3.4 TWh in the Regional Steering scenario and 29 TWh in the International Steering scenario. Part of the variation between these scenarios can be explained by the number of kilometers traveled[32] by trucks and the number of FCEV[33].

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[30] In the ADAPT scenario, steel and ethylene production in 2050 is 7.5 Mt and 4.83 Mt, respectively, whereas steel production is 5.63 Mt and ethylene production is 3.94 Mt in the TRANSFORM scenario

[31] The REDIII requires that the share of renewable fuels of non-biological origins (RFNBOs) in the mobility sector reaches 2.6% in 2030. This obligation also includes bunker fuels for international shipping and aviation. Therefore, 7.6 of TWh green hydrogen should be produced in 2030 for the mobility sector (Hers et al., 2022, p.19).

[32] In the Regional Steering scenario, 30% less freight will be transported. In the National Steering scenario, the amount of freight transported stays constant, and freight transport increases by 42% in the European Steering and International Steering scenarios.

[33] The percentage of FCEV in LDVs and HDVs is 15% in the Regional Steering scenario, 50% in the National Steering scenario, and 25% in the European Steering and International Steering scenarios.

Table 9: the use of green hydrogen in the built environment, the mobility sector, industry, and as feedstock. Hydrogen use for electricity generation is not taken into account.

Name study	Name scenario	Scenario year	Hydrogen use in Built environment [TWh]	Hydrogen use in mobility [TWh]	Hydrogen use in industry [TWh]	Hydrogen use in feedstock [TWh]	Electrolyzer capacity [GW]
KEV 2021	Reference	2019	0	0	0	0	0
		2030	0	0	0	0	0
Werkgroep Extra Opgave	49% CO_2 reduction	2030	0	0	5[16]	0	2[34]
	55% CO_2 reduction	2030	0	0	12[35]	0	6[15]
	55% CO_2 reduction + REDIII	2030	0	8	15[16]	0	11
KIVI 2020		2050	0	44	60	-	40
II3050	Regional Steering	2050	0	3	23	4	42
	National Steering	2050	0	18	43	8	51
	European Steering	2050	15	25	80	19	19
	International Steering	2050	46	29	73	37	16
TNO 2022	ADAPT	2050	13	17	54[36]	-	20
	TRANSFORM	2050	1	17	202[17]	-	67

Further, it is assumed that hydrogen will play an important role in the industry. In the 49% reduction scenario of the Werkgroep Extra Opgave, 4.8 TWh of green hydrogen is needed to decarbonize Tata Steel in 2030 (Hers et al., 2022, p.12). The 55% reduction scenario and the 55% reduction + REDIII scenario estimate a higher hydrogen use in the industry. In these scenarios, green hydrogen will be used to produce ammonia and methanol and in production processes in refineries in 2030 (Hers et al., 2022, p.15). The KIVI 2020 estimates that 27 TWh of hydrogen will be used to produce ammonia, 20 TWh to produce steel, and 13 TWh will be used for other industries in 2050 (Persoon et al., 2020, p.25). In the II3050, hydrogen use in industry differs due to the size of the industry and to what extent hydrogen is used for heating in industrial processes. Additionally, hydrogen only has a minor role in energy use for heating in the TNO 2022 study (Scheepers et al., 2022, p.47-48)

Finally, hydrogen can be used as feedstock. In the TRANSFORM scenario of TNO 2022, hydrogen is used to produce the majority of the feedstock. In the ADAPT scenario, the feedstock is mostly based on crude oil (Scheepers et al., 2022, p.35). Moreover, the II3050 uses mainly fossil fuels as feedstock in each scenario in 2050 (Netbeheer Nederland, 2021, p.25-28). The KIVI 2020 uses biomass as feedstock (Persoon et al., 2020, p.25).

4.8. Estimations of future electricity supply

This section elaborates on the estimations of electricity generation capacities in the energy scenarios. The estimations for offshore wind capacity range from 12 GW to 17 GW in 2030. The estimations for offshore wind capacity range from 28 GW to 72 GW in 2050. Table 10 shows that the amount of onshore wind power capacity in the Dutch energy scenarios ranges from 6 to 20 GW in 2050. Most scenario studies assume onshore wind capacities to be between 8 and 10 GW. The Regional Steering and the National Steering scenarios of the II3050 assume a capacity that is substantially more than 10 GW.

[34] Electrolyzer is assumed with 3500 operating hours (Hers et al., 2022, p.12-13).

[35] An efficiency of 58 percent (LHV) is assumed for electrolysis in this study (Hers et al., 2022, p.56).

[36] Hydrogen consumption for energetic energy use and feedstock are combined.

The amount of solar power capacity differs much in the different scenarios. There was 11 GW of solar power capacity installed in the Netherlands at the end of 2020 (PBL, 2021, p.105). According to the KEV 2021, solar power capacity is expected to increase to 25 GW in 2030. For 2050, the solar power capacity estimations range from 38 GW in the Global Ambition scenario of the TYNDP to 125 GW in the Regional Steering scenario of the II3050. Hence, the role of solar power varies strongly per future energy scenario.

In addition, nuclear power is included in the TRANSFORM scenario of TNO 2022 and has a capacity of 5 GW in 2050. In the KEV 2021 and the Werkgroep Extra Opgave, the nuclear power plant in Borsele is still operating. Nuclear power does not play a role in all other energy scenarios.

Conventional electricity generation, defined here as electricity produced by burning fuels such as coal, natural gas, or renewable gases, is expected to decrease. Most electricity generated in the Netherlands was produced by conventional generation in 2019. In 2050, the conventional power plants' capacities will range from 4 GW in the TRANSFORM scenario of TNO 2022 to 48 GW in the Distributed Energy scenario of the TYNDP 2022. Most energy scenario studies estimate at least 30 GW of conventional power plant capacity in the Netherlands.

Lastly, the role of electricity imports differs per scenario The Netherlands will become an electricity importer in the KIVI 2020 and in the ADAPT scenario of TNO 2022. On the other hand, the Netherlands exports electricity in the Regional Steering and the National Steering scenario of the II3050. Therefore, whether the Netherlands becomes a net importer or exporter of electricity is uncertain.

Table 10: overview of electricity generation capacities [GW] in the Netherlands in different scenario studies.

Name study	Name scenario	Scenario year	Offshore wind	Onshore wind	Solar PV	Nuclear power	Conventional power plants	Other renewable power plants
KEV 2021	Reference	2019	1	4	7	0.476	37	1
		2030	12	8	25	0.476	21	0
Werkgroep Extra Opgave		2030	17	8	25	0.476	21	0
KIVI 2020		2050	60	6	77	0	33	3
II3050[8]	Regional Steering	2050	31	20	125	0	33	0
	National Steering	2050	52	20	107	0	35	0
	European Steering	2050	30	10	58	0	36	0
	International Steering	2050	28	10	52	0	36	0
TNO 2022	ADAPT	2050	40	8	107	0	13	0
	TRANSFORM	2050	70	12	132	5	4	0
TYNDP 2022	Distributed energy	2050	60	10	44	0	48	1
Netherlands[9]	Global Ambition	2050	72	9	38	0	35	1

Table 11: overview of electricity generation [TWh] in the Netherlands in different scenario studies.

Name study	Name scenario	Scenario year	Offshore wind	Onshore wind	Solar PV	Nuclear power	Conventional power plants	Other renewable power plants	Net electricity imports	Total electricity generation
KEV 2021	Reference	2019	2	10	5	4	92[7]	8	-3	121
		2030	50	23	23	3	38[37]	5	-9	143
Werkgroep Extra Opgave		2030	77	23	23	3	35	0	0	165
KIVI 2020		2050	269	14	71	0	16	20	40	374
II3050	Regional Steering	2050	116	45	105	0	3	0	-8	223
	National Steering	2050	192	45	89	0	2	0	-10	258
	European Steering	2050	112	23	48	0	67	0	13	250
	International Steering	2050	103	23	44	0	74	0	16	242
TNO 2022	ADAPT	2050	192	33	89	0	5	0	53	315
	TRANSFORM	2050	386	54	120	43	0	0	8	603
TYNDP 2022	Distributed energy	2050	274	24	43	0	63	2	-	406
Netherlands	Global Ambition	2050	326	22	36	0	34	2	-	442

[37] Including 'other fossil' energy generation.

4.9. Capacity factors of renewable energy technologies

The capacity factors of offshore wind power, onshore wind power, and solar PV of the analyzed scenario studies are discussed in this section. The capacity factor is the unitless ratio of net electricity generated, for the time considered, over the maximum potential electricity generation during the same period (U.S.NRC, 2021). The capacity factors are calculated using the following formula:

$$capacity\ factor = \frac{electricity\ generation\ [\frac{MW}{h}]}{365\ [days] \cdot 24 \left[\frac{hours}{day}\right] \cdot nominal\ capacity\ [MW]} \quad (3)$$

The results are shown in Table 12. The capacity factors of offshore wind power range from 42% to 63%, the capacity factors of onshore wind range from 25% to 51%, and the capacity factors of solar PV range from 9% to 11%. The capacity factors for renewable energy in the II3050 are relatively low because the weather year 1987 was chosen, which was a year with relatively little solar and wind (Netbeheer Nederland, 2021, p.24). The TNO 2022 scenario study has optimistic capacity factors for offshore wind energy relative to historic capacity factors in the Netherlands[38]. Moreover, the capacity factor of onshore wind power is low in the TYNDP 2022 scenarios of the Netherlands because measured average capacity factors in Europe are above 30% (International Renewable Energy Agency, 2022, p.69)

Lastly, the ratio of wind power and solar power capacity is calculated for each scenario. The ratio of wind power capacity and solar power capacity ranges from 0.5 in the Global Ambition scenario of the TYNDP 2022 to 2.5 in the Regional Steering scenario of the II3050. Hence, the ratio of wind and solar power differs substantially between scenarios.

Table 12: capacity factors of onshore wind, offshore wind and solar PV in the different energy scenario studies.

Name study	Name scenario	Scenario year	Capacity factor offshore wind [%]	Capacity factor onshore wind [%]	Capacity factor solar PV [%]	Ratio solar power and wind power capacity
KEV 2021		2030	48	33	11	1.3
Werkgroep Extra Opgave		2050	52	33	11	1.0
KIVI 2020	Reference	2015	51	27	11	1.2
II3050	Regional Steering	2050	43	26	10	2.5
	National Steering	2050	42	26	9	1.5
	European Steering	2050	43	26	9	1.5
	International Steering	2050	42	25	10	1.4
TNO 2022	ADAPT	2050	55	48	9	2.2
	TRANSFORM	2050	63	51	10	1.6
TYNDP 2022	Distributed Energy	2050	52	21	11	0.6
Netherlands	Global Ambition	2050	52	20	11	0.5

4.10. Relation estimated offshore wind capacity with electricity demand and green hydrogen production in the Netherlands

This section discusses the relation between offshore wind capacity and electricity demand in the Netherlands and the relation between offshore wind capacity and green hydrogen production in the Netherlands. The correlation between electricity demand and offshore wind capacity is shown in Figure 1. The data points of electricity demand are taken from Table 4. These observations are matched with the offshore wind capacity from Table 6. The corresponding offshore wind generation is calculated using the following equation:

[38] The capacity factor of offshore wind in the Netherlands was 46% in 2021 based on (International Renewable Energy Agency, 2022, p.115).

$$capacity\ factor = \frac{electricity\ generation\ [\frac{MW}{h}]}{365\ [days] \cdot 24\ [\frac{hours}{day}] \cdot nominal\ capacity\ [MW]} \quad (3).$$

The Netherlands' estimated offshore wind capacity strongly correlates with electricity demand. This means that scenarios with a high electricity demand also tend to have a large estimated offshore wind capacity. In addition, it can be observed that about 150 TWh is generated by other energy generation sources such as solar energy and onshore wind. The remaining electricity demand is supplied by offshore wind in these energy scenarios. Hence, according to the examined scenario studies, extra electricity demand is largely supplied by extra offshore wind capacity.

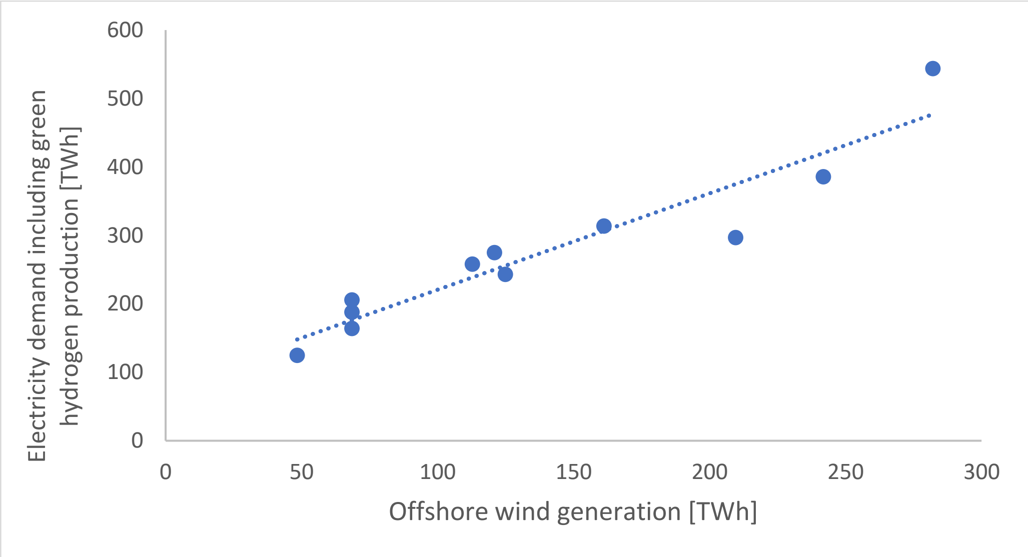

Figure 1: relation between offshore wind generation and electricity demand. A capacity factor of 46% for offshore wind capacity is assumed.

Moreover, offshore wind capacity correlates with green hydrogen production in the investigated scenarios. This relation is illustrated in Figure 2. The data points of electricity use for hydrogen production are taken from Table 4, and these observations are matched with the offshore wind capacity from Table 6.

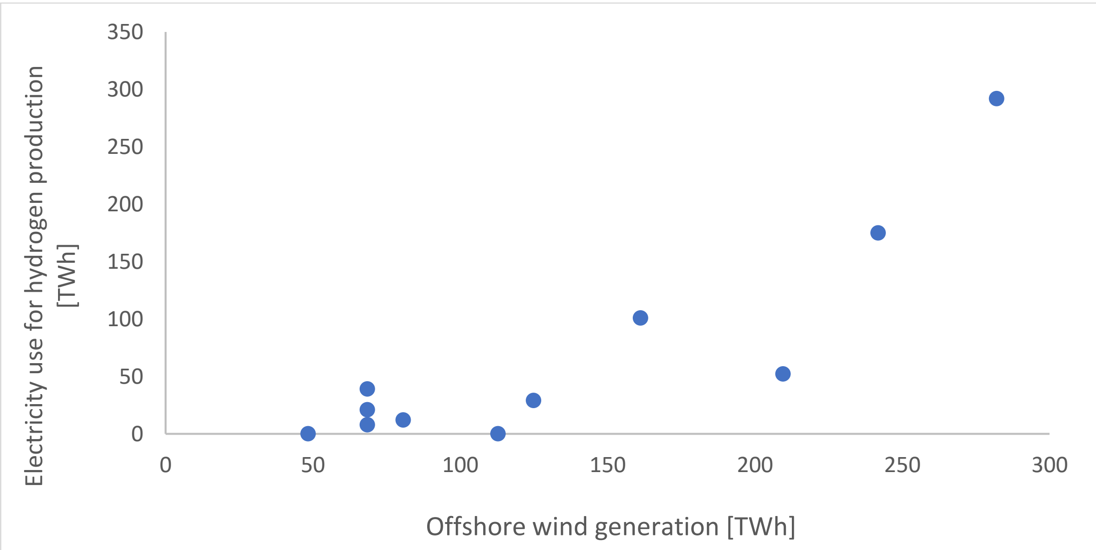

Figure 2: relation between offshore wind generation and green hydrogen production. A capacity factor of 46% for offshore wind capacity is assumed.

It can be observed that scenarios with high electricity use for hydrogen production also tend to have high offshore wind capacities. Scenarios with electricity use of fewer than 50 TWh for hydrogen consumption have between 50 and 125 TWh generated from offshore wind. Electricity consumption for green hydrogen production scales linearly with offshore wind generation from about 150 TWh offshore wind generation. This means that extra electricity demand in the Netherlands is mainly driven by more electricity consumption for green hydrogen production after electricity generation in the Netherlands reaches 250 TWh.

4.11. Conclusions scenario analysis

This section presents the conclusions of the scenario analysis. The results of the electricity use in the Netherlands are shown in Figure 3. When heating is excluded, the expected change in the built environment is very modest and depends on the future number of commercial and residential buildings. The share of heat pumps in the heat supply largely explains the difference in electricity use for heating in the built environment. Other technologies to reduce CO_2 emissions in the heat supply in the built environment are heat networks, geothermal heat, and heating using sustainable gasses such as green hydrogen and biomethane. In agriculture, the estimations of future electricity demand range by a factor of two. However, the high future electricity use of 25 TWh in agriculture lacks substantiation, and the qualitative differences in electricity use might be smaller than presented. Differences in electricity use in the mobility sector can be explained by changes in travel behavior and the number of electric vehicles in the future. Most scenarios expect electric vehicles to become dominant in passenger transport. However, it is uncertain to what extent they are used for light and heavy-duty transport.

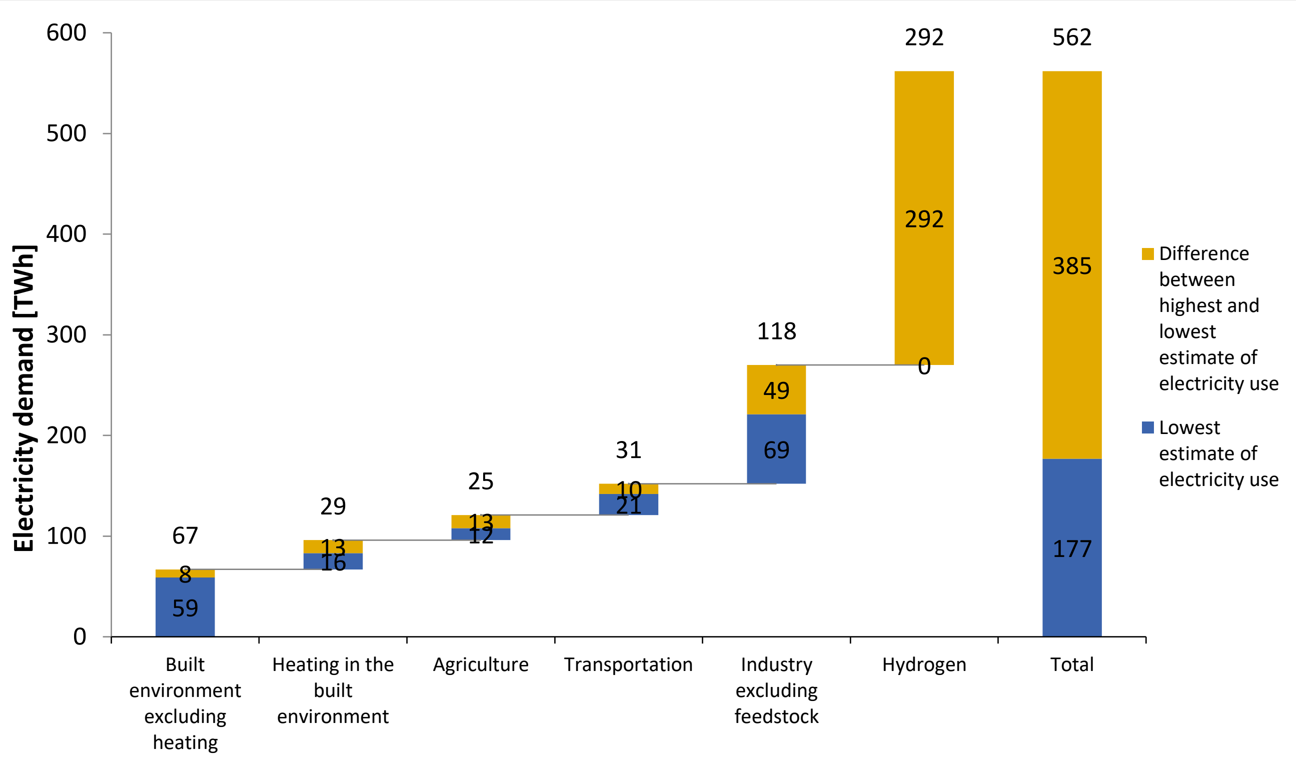

Figure 3: Overview of electricity use in the Netherlands in 2050 aggregated by sector.

Moreover, differences in the electricity use in industry can be explained by the future size of the energy-intensive industry and the electrification rate of the industry. The largest difference can be seen in the estimated electricity use for green hydrogen production. This difference depends on the extent to which sector coupling becomes a reality in the Netherlands. Hydrogen consumption for heating in the built environment plays a minor role in the reviewed scenario studies. It is only used on a small scale for heating in the built environment when cheap hydrogen can be imported from abroad. Hydrogen consumption in transportation, as fuel in industry, and hydrogen use as feedstock remains uncertain. In addition, there is no consensus on whether hydrogen should be produced domestically or imported from abroad.

Scenario estimations of renewable and conventional generation technologies are shown in Figure 4. It is expected that solar and wind energy will play a major role in a highly decarbonized Dutch energy system. New nuclear power plants are only considered in one scenario; most electricity will still be produced with wind and solar energy. Other renewable energy technologies play a minor role in the electricity supply in future energy scenarios of the Netherlands. There is also a significant difference in the estimations of conventional power plants. Conventional power plant capacity is used chiefly for dispatchable backup capacity, and scenarios studies differ in how flexibility is built into the energy system.

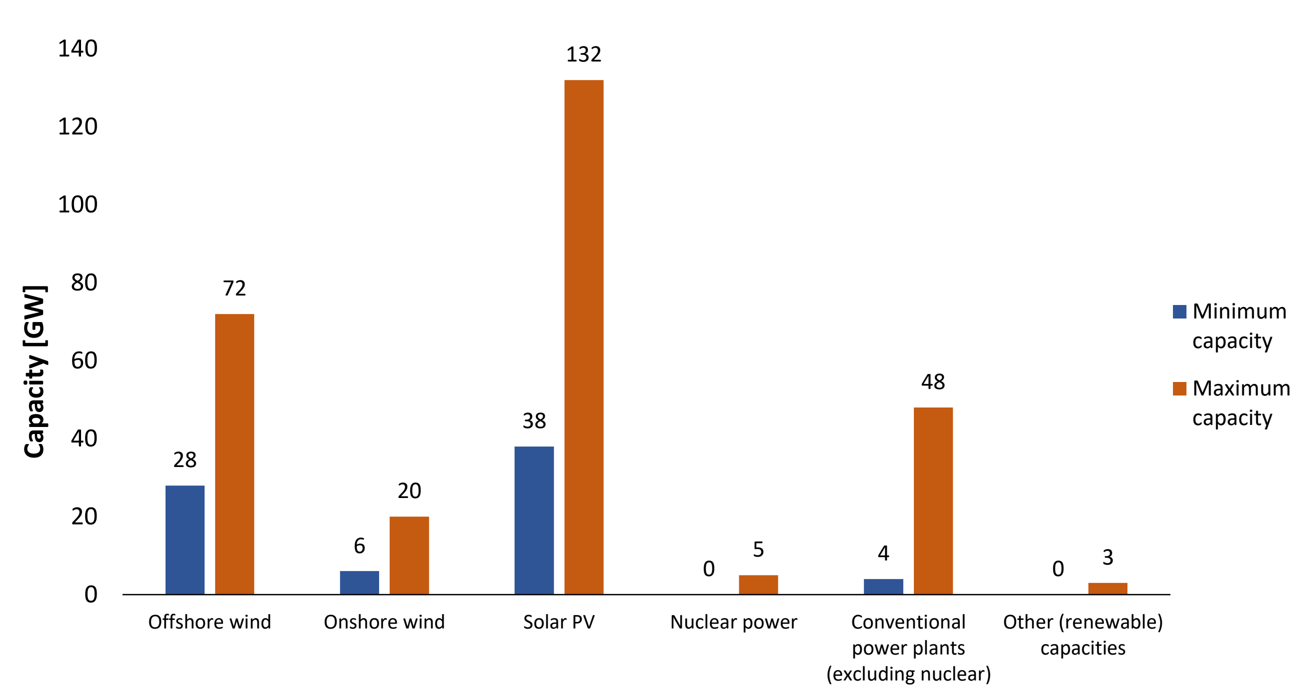

Figure 4: Overview of estimations of future generation capacities aggregated by technology in the Netherlands in 2050.

The results of the scenario analysis show that without hydrogen, the electricity demand of the Netherlands in a highly decarbonized energy system ranges from 177 TWh to 270 TWh. If the most conservative assumptions for onshore wind power and solar power capacities are assumed, with capacity factors of 33% for onshore wind and 10% for solar PV, between 126 TWh and 219 TWh needs to be covered with offshore wind energy. This corresponds to 30 GW and 52 GW offshore wind capacity in the Netherlands in 2040, assuming a capacity factor of 48%[39] for offshore wind. This means that electrification in the built

[39] It is also assumed that there is no net electricity trade and no electricity generation by other energy generation technologies. Supply and demand should be perfectly matched with demand response. In practice, the latter would not be feasible.

environment, agriculture, transport, and industry can create sufficient electricity demand for the lower bound of 38 GW offshore wind power. The higher bound of 72 GW offshore wind capacity can only be reached when electricity is used for green hydrogen production in the Netherlands.

In conclusion, the differences in future electricity demand in the Netherlands when hydrogen is not considered are modest compared to the differences in estimated electricity use for green hydrogen production. Extra offshore wind is mainly deployed when scenario studies assume a higher future electricity demand in the Netherlands. Large uncertainties remain in domestic green hydrogen production, which is mainly produced by electricity generated by offshore wind farms in energy scenarios. Therefore, the question remains to what extent hydrogen will be used as an energy carrier to decarbonize transportation, industrial heating, and feedstock. It also remains uncertain whether the Netherlands will produce green hydrogen domestically or import it from abroad. Subsequently, this determines if the upper bound of 70 GW offshore wind is necessary to match electricity demand.

5. Modeling framework

This research examines the system effects of offshore wind power in the Dutch part of the North Sea in 2040. In this chapter, the model that is used to answer the second research sub-question introduced in section 1.4 is presented. Section 5.1 provides an overview of the model logic. After that, section 5.2 presents a mathematical description of the used model based on PyPSA-Eur. Section 5.3 describes the methodology to formalize the model. Furthermore, sections 5.4 to 5.8 give a description of the data inputs. These data inputs include electricity demand, electricity generation technologies, data inputs for the transmission infrastructure, electricity storage, and technology cost assumptions. Lastly, sections 5.9 and 5.10 provide a description of the modeling setup. The results of the formulated scenarios are analyzed to obtain insight into the system effects of offshore wind power.

5.1. Description of the modeling framework

A highly renewable energy system of the North Sea countries is modeled in this study. Figure 5 shows a brief flowchart summarizing the methodological elements and steps followed by the PyPSA-Eur model. The backbone of the model is a mathematical graph that consists of nodes that are interconnected via edges. Power plants and storage are connected to the nearest node, transmission network data is connected to edges, and technological characteristics and costs are attributed to the power plants and storage. Electricity demand and wind and solar time series are exogenous variables.

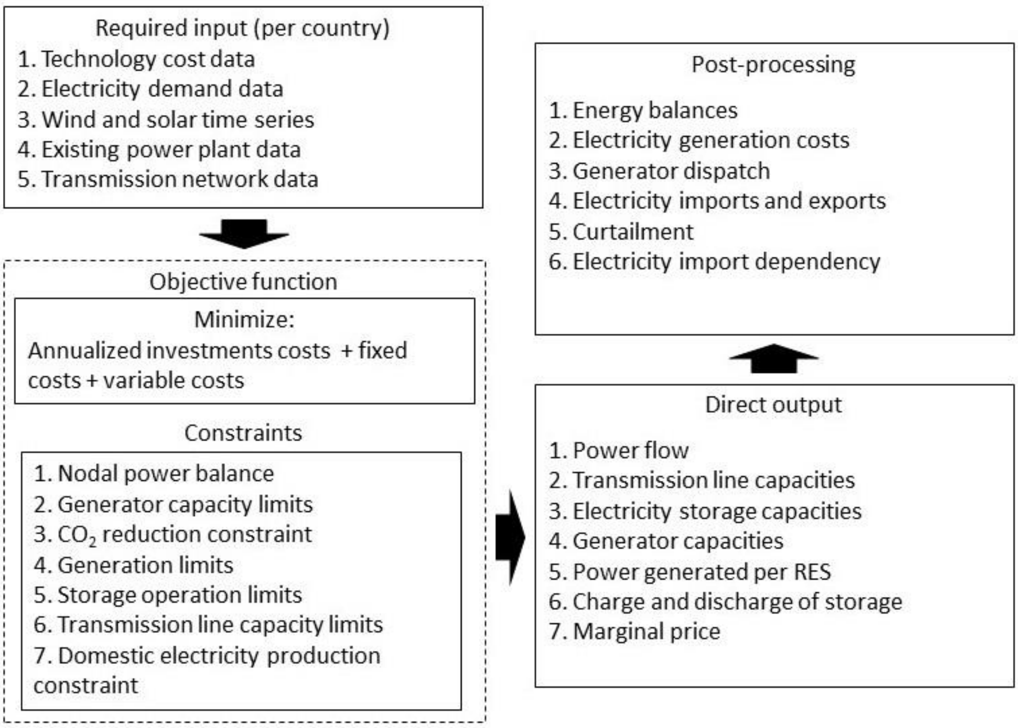

Figure 5: Methodological elements of the used model based on PyPSA-Eur.

The model is formulated as a techno-economic linear optimization model that minimizes annual system costs. The research adopts a simulation period of one year with 3-hourly time steps. The generators, storage, and transmission line capacities are subject to optimization. They are therefore determined in a cost minimization subject to various constraints. The nodal energy balance ensures that the energy at each node is balanced at each point in time. The CO_2 emission reduction constraint sets the maximum allowed emissions of the energy system. The domestic electricity generation constraint requires every country to produce a certain percentage of its domestic electricity demand. Furthermore, the generator and transmission line capacity limits set the minimum and maximum capacities of power plants and transmission lines in the optimization. The storage operation limits determine the maximum discharge time of a storage unit, and the generation limits ensure that a power plant does not exceed its maximum available dispatch.

The optimization generates several results. For every time step, the power produced per generator, the charge or discharge of storage units, and the power flow over the transmission lines are calculated. Furthermore, the cost-optimal generator, storage, and transmission line capacities are calculated in the optimization. The corresponding marginal prices are also calculated at each node. In the final step, these results are used to calculate several metrics, such as renewable energy curtailment, electricity imports and exports, and electricity generation costs.

5.2. Mathematical description of the model

This section describes PyPSA-Eur based on (Frysztacki et al., 2021; Hörsch, Hofmann, et al., 2018; Hörsch, Ronellenfitsch, et al., 2018; Hörsch & Brown, 2017; Neumann & Brown, 2021; Parzen et al., 2022). The objective of PyPSA-Eur is to minimize the total system costs, which are composed of annualized capital and operational expenses. The overnight[40] capital costs are annualized to net present costs with a discount rate r over the economic lifetime n using the annuity factor AF. The model assumes perfect competition and perfect foresight[41]. The annuity factor converts the overnight investment of an asset to an annual payment, considering the lifetime and the capital cost. The annuity factor is calculated using the following equation:

$$AF = \frac{1-(1+r)^{-n}}{r} \tag{4}$$

5.2.1. Objective function

The capital expenditures consist of the long-term, capacity-related investment costs c, at location i, for generator $G_{i,r}$ of technology r, and the capacity-related investment costs c of transmission line F_l. Furthermore, the capital expenditures include storage energy capacity $H_{i,s}^{store}$, charging capacity $H_{i,s}^{charge}$, discharging capacity $H_{i,s}^{discharge}$ of technology s.

The operational expenses consist of energy-related variable costs o for generator $g_{i,r,t}$ of technology r. The operational expenditures also consist of storage charging $h_{i,s,t}^{charge}$, storage discharging $h_{i,s,t}^{discharge}$, as well as the energy storage costs $e_{i,s,t}$. Furthermore, the operation depends on the time steps t that are weighted for duration w_t. When time steps of 1 hour are chosen, the time steps will sum up to one year $\sum_{t=1}^{T} w_t = 365\text{days} \cdot 24\text{h} = 8760\text{h}$. This lead to the following objective function:

$$\min_{G,H,F,g,h,e} \quad \text{Total system costs} =$$

[40] The overnight capital costs are the capital costs of building a power plant overnight without considering financing costs during construction.

[41] In a model with perfect foresight, decision-makers have perfect knowledge concerning future events. As a result, the solution represents an ideal transition pathway for energy systems. In contrast, decision-makers are not able to perfectly predict the future in a myopic optimization model.

$$
\begin{aligned}
\min_{G,H,F,g,h,e} \quad & [\sum(c_{i,r} \cdot G_{i,r}) + \sum(c_l \cdot F_l) \\
& + \sum_{i,s}(c_{i,s}^{store} \cdot H_{i,s}^{store} + c_{i,s}^{charging} \cdot H_{i,s}^{charging} + c_{i,s}^{discharging} \cdot H_{i,s}^{discharging}) \\
& + \sum_{i,r,t}(o_{i,r} \cdot g_{i,r,t} \cdot w_t) \\
& + \sum_{i,r,t}((o_{i,s}^{charging} \cdot h_{i,s,t}^{charging} + o_{i,s}^{discharging} \cdot h_{i,s,t}^{discharging}) \cdot w_t) \\
& + \sum_{i,r,t}(o_{i,s}^{store} \cdot e_{i,s,t} \cdot w_t)] \qquad (5)
\end{aligned}
$$

The objective function must satisfy a number of constraints. These constraints are specified in the following paragraphs.

5.2.2 Power balance constraints

The power flows are constrained by two Kirchhoff circuit laws for the current and the voltage (Hörsch, Ronellenfitsch, et al., 2018). Kirchhof's current law (KCL) requires that local electricity generators, storage units, and incoming and outgoing power flow $f_{l,t}$ of incident transmission lines l in a closed cycle network must balance the inelastic electricity demand $d_{i,t}$ at each location i and snapshot t. KCL implies power conservation.

$$\sum_r g_{i,r,t} + \sum_s h_{i,s,t} + \sum_l K_{i,l} f_{l,t} = d_{i,t} \qquad \forall\, i,t \qquad (6)$$

Moreover, Kirchhof's voltage law (KVL) must be enforced in each connected network (Hörsch, Hofmann, et al., 2018; Hörsch, Ronellenfitsch, et al., 2018). KVL requires that the voltage angle difference around every closed cycle in a network must sum to zero. If each independent cycle is expressed as a directed linear combination of passive lines l in a cycle incidence matrix where x_l is the series inductive reactance of line , then KVL becomes the following constraint:

$$\sum_t C_{l,c} \cdot x_l \cdot f_{l,t} = 0: \qquad \forall\, i,t \qquad (7)$$

Further, energy demand and generation have to match every hour in each node. This is necessary to ensure a stable operation of the electrical grid. The inelastic demand at location i at time t is given by $d_{i,t}$. This leads to the following equation:

$$\sum_s g_{i,s,t} - d_{i,t} = \sum_l k_{i,l} f_{l,t} \leftrightarrow \lambda_{n,t} \qquad (8)$$

where $k_{i,l}$ is the incidence matrix of the network. Furthermore, $\lambda_{n,t}$ is the Karush-Kun-Tucker multiplier, which is associated with the constraint that indicates the marginal price of supplying additional demand at location i and time t. This is also known as the locational marginal price, and the value of $\lambda_{i,t}$ is an outcome of the optimization (Schlachtberger et al., 2017).

5.2.3. Generator, storage and transmission constraints

The objective function is also subject to a set of linear constraints, and these constraints transform the objective function into a convex linear problem. The capacities of generators, electricity storage, and transmission infrastructure are constrained by the existing capacities and their geographic potential (Neumann & Brown, 2021):

$$G_{i,r}^{lower\_limit} \leq G_{i,r} \leq G_{i,r}^{upper\_limit} \qquad \forall\, i,r \qquad (9)$$

$$H_{i,s}^{lower\_limit} \leq H_{i,s} \leq H_{i,s}^{upper\_limit} \qquad \forall\, i, s \tag{10}$$

$$F_{l}^{lower\_limit} \leq F_{l} \leq F_{l}^{upper\_limit} \qquad \forall\, l \tag{11}$$

The availability of variable renewable energy, which is derived from reanalysis of weather data, also constrains the dispatch of generators:

$$0 \leq g_{i,r,t} \leq g_{i,r,t}^{upper\_limit} \cdot G_{i,r} \qquad \forall\, i, r, t \tag{12}$$

The amount of energy that can be stored is limited by the energy capacity of the storage unit. The dispatch of storage units for charging and discharging is limited by the power rating $H_{i,s}$ of the storage units.

$$0 \leq e_{i,s,t} \leq H_{i,s}^{store} \qquad \forall\, i, s, t \tag{13}$$

$$0 \leq h_{i,s,t}^{charging} \leq H_{i,s} \qquad \forall\, i, s, t \tag{14}$$

$$0 \leq h_{i,s,t}^{discharging} \leq H_{i,s} \qquad \forall\, i, s, t \tag{15}$$

In order to prevent simultaneous charging and discharging, the energy levels $e_{i,s,t}$ have to be consistent with the dispatch at all hours and are limited by the storage capacity. In addition, the storage units have a charging efficiency $\eta^{charging}$, a discharging efficiency $\eta^{discharging}$, a natural inflow h^{inflow}, and spillage $h^{spillage}$.

$$e_{i,s,t} = e_{i,s,t-1} + \eta^{charging} h_{i,s,t}^{charging} + \eta^{discharging} h_{i,s,t}^{discharging} + h_{i,s,t}^{inflow} + h_{i,s,t}^{spillage} \tag{16}$$

The energy levels of the storage facilities are assumed to be cyclic. This avoids the free use of storage endowment, which means that the model cannot end up with a lower storage level than it starts with.

5.2.4. Transmission constraints

The flow in all transmission lines $f_{l,t}$ are constrained by their capacity F_l, and this can be formulated as follows

$$|f_{l,t}| \leq F_l \qquad \forall\, l, t \tag{17}$$

The sum of all transmission line capacities (HVAC and HVDC) multiplied by their lengths l_l is restricted by a line volume cap $CAP_{transmission}$ which can be varied in different scenarios (Hörsch, Hofmann, et al., 2018). The caps are defined relative to existing line capacities F_l^{today}. This way, the effect of transmission expansion on the system can be investigated.

$$\sum_l l_l \cdot F_l^{today} \leq CAP_{transmission} \tag{18}$$

5.2.5. CO_2 emission constraint

Lastly, the total CO_2 emissions must not exceed an emission limit CAP_{CO_2}. These emissions are implemented using the specific emissions ρ_r of the fuel r in CO_2-tonne-per-MWh and the generator efficiencies $\eta_{i,r}$

$$\sum_{i,r,t} \frac{1}{\eta_{i,r}} w_t \cdot g_{i,r,t} \cdot \rho_r \leq CAP_{CO_2}. \qquad (19$$

5.3. Model formalization

The open model dataset PyPSA-Eur is used as a numerical implementation of the power sector of the North Sea countries (Hörsch, Hofmann, et al., 2018). The model has a spatial resolution of 40 transmission nodes and a temporal resolution of 2920 snapshots (3-hourly for an entire year). The network model is shown in Figure 6. It is chosen to use a 3-hour temporal resolution to capture changes in solar generation and electricity demand while reducing computation times (Frysztacki et al., 2021, p.4). First, the desired number of clusters n is partitioned between the ten North Sea countries (Frysztacki et al., 2021, p.5). After that, techniques based on k-means clustering are used to partition the network into a given number of zones, and the network is then reduced to a representation of one bus per zone. The simplification and clustering steps are described in (Hörsch & Brown, 2017, p.2).

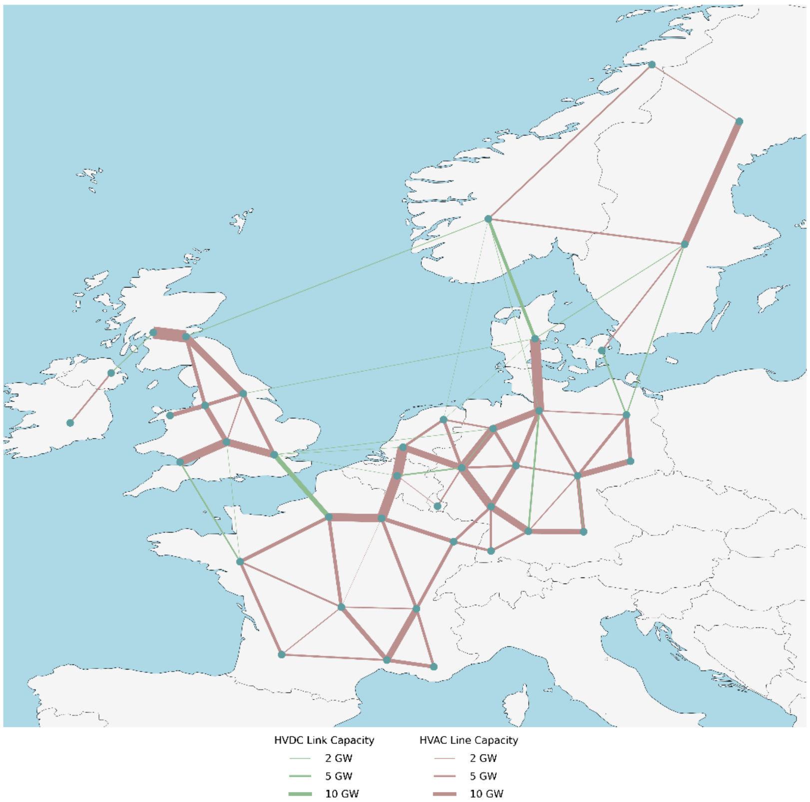

Figure 6: PyPSA-Eur model of the electricity system of the North Sea countries including all existing high-voltage alternating current (HVAC) and high-voltage direct current (HVDC) lines.

The level of geographical aggregation also influences the modeling results. A higher resolution allows the optimal solution to concentrate wind and solar power capacities to allocate at sites with better capacity factors. This reduces the system costs by up to 10% compared to a low-resolution model. When grid bottlenecks are introduced by raising the network resolution, costs increase by up to 23% as electricity generation has to be located at sites with suboptimal capacity factors. Allowing grid expansion mitigates some of the effects of low grid resolution (Frysztacki et al., 2021). Even though a low-resolution model is likely to underestimate the system costs, it is chosen to use a 40-nodes model to keep the computation times reasonable.

The model is run with perfect foresight over a historic year of weather data from 2013, assuming a 100% reduction in CO_2 emissions compared to 1990. The weather data is from the ECMWF ERA5 reanalysis dataset and the CMSAF SARAH-2 solar surface radiation dataset (Hörsch et al., 2022). The data is prepared with the Atlite tool (Hofmann et al., 2021).

5.4. Electricity demand

Electricity demand is an important import factor in the power sector investment modeling step. The electric load curve is expected to change substantially in the coming decades, and the evolving structure of electricity demand drives this change. Major drivers behind the load curve transformation are energy efficiency improvements, new demand-side technologies such as heat pumps and electric vehicles, and macroeconomic factors (Bobmann & Staffell, 2015).

Consequentially, the load data of the Global Ambition scenario in 2040 of the TYNDP 2022 is used (ENTSOG & ENTSO-E, 2022c). The load data is based on the climate year 2008. It is chosen to use the Global Ambition scenario[42] because it focuses on large-scale technologies such as offshore wind and large storage facilities. The energy transition in the Global Ambition scenarioo is initiated on a European or international level, and this focus aligns with the objective of this research (ENTSOG & ENTSO-E, 2021). The electricity demand in each of the North Sea countries is shown in Table 13.

Table 13: historic electrity demand of the North Sea countries in 2013 and projected electricity demand in 2040 according to the Global Ambition scenario of the TYNDP 2022.

Country	Historic electricity demand in 2013 [TWh][43]	Electricity demand in 2040 [TWh]
Belgium	86	109
Denmark	32	60
France	492	620
Germany	509	773
Ireland	26	46
Luxembourg	6	13
Netherlands	114	195
Norway	128	181
Sweden	140	162
United Kingdom	336	552

In the Global Ambition scenario, 54% of passengers' cars, 45% of buses, 84% of trains, 16% of LDV, and 15% of HDV are electric in the Netherlands. For residential heating, 45% of the heat is supplied by electric heat pumps, and hybrid heat pumps supply 17% of the heat. In the tertiary sector, 52% of the heat is supplied by electric heat pumps, and 17% is supplied by hybrid heat pumps in 2040 in the Netherlands. Heat pumps switch on when the outside temperature is below 16 ^{o}C; if the outside temperature reaches 5 ^{o}C, the consumption switches to methane or hydrogen in hybrid heat pumps (ENTSOG & ENTSO-E, 2022c).

Figure 12 displays the historic electricity demand of the North Sea countries in 2013 and the electricity demand in 2040 according to the Global Ambition scenario of the TYNDP 2022. It can be seen that the electricity demand in each North Sea country increases in the Global Ambition scenario. The sharpest relative electricity demand change is in Luxembourg, and the smallest is in Sweden. Moreover, the model's

[42] The Distributed Energy scenario is another scenario of the TYNDP 2022, and this scenario focuses more on decentralized technologies such as solar PV and batteries. Furthermore, the energy transition is initiated on a local or national level.

[43] The electricity demand data are takenn from the ENTSO-E (ENTSO-E, 2019).

geographical load distribution in each country is based on population statistics and GDP for the NUTS3 regions. The two statistics are mapped from the Eurostat Economic Accounts database to the Voronoi cells in proportion to their geographic overlap (Hörsch, Hofmann, et al., 2018, p.5). The total load in the North Sea countries in 2040 is 2711 TWh, up from 1869 TWh in 2013. The electricity load curve is shown in Figure 11 of Appendix B.

5.5. Electricity generators

Electricity generation is allowed for the following technologies: hydroelectricity, onshore wind power, offshore wind power, solar PV, nuclear power, and fuel cells[44]. Biomass power plants, fossil power plants, and geothermal power plants are not considered in this study. Biomass power generation is not considered because domestic biomass production in the Netherlands is limited. According to Scheepers et al. (2022), Dutch domestic biomass production ranges from 179 PJ to 246 PJ. The available biomass is often used in scenario studies to decarbonize industry, feedstock, heating, and transportation instead of electricity generation (Netbeheer Nederland, 2021; Scheepers, Palacios, Janssen, et al., 2022). Fossil fuel generation is not included because it requires CCS to be CO_2-neutral, and CCS can also be used for negative emissions (Haszeldine et al., 2018). Moreover, this research does not consider geothermal power generation because it is not part of future energy scenarios (Netbeheer Nederland, 2021; Scheepers, Palacios, Janssen, et al., 2022).

Wind and solar-based technologies are greenfield optimized[45] because there is a lack of data availability in many countries. Several constraints restrict the usable land for onshore wind power. Wind turbines can only be installed in agricultural areas, forests, and semi-natural areas. In addition, a minimum distance of 1000 meters from urban, industrial, and transported units must be respected. Offshore wind can only be installed in water depths lower than 50 meters, and wind turbines cannot be placed in areas listed as Natura2000 areas (Hörsch, Hofmann, et al., 2018). Moreover, the maximum onshore wind installation density is 5 MW/km^2, and the maximum offshore wind installation density is 3 MW/km^2.

Furthermore, each country's maximum onshore wind power capacity is confined because onshore wind lacks public support (NOS Nieuws, 2021). The Netherlands' maximum onshore wind is constrained to 8 GW, which is equal to the projected onshore wind capacity in the KEV for 2030 (PBL, 2021). The technical potential for onshore wind power in other North Sea countries is shown in Table 14. The power curve of the NREL reference turbine 2020ATB with a turbine capacity of 4 MW is used for onshore wind time series. For offshore wind time series, the power curve of the NREL reference turbine 2020ATB with a turbine capacity of 15 MW is used. Offshore wind turbines can either be installed with AC or DC grid connections. An HVAC connection is used when the wind turbines are located less than 30 kilometers from the shore. An HVDC connection is used when the wind turbines are installed further away from the shore.

Additionally, the reference solar panel is a crystalline silicon panel. The maximum installation density for solar power capacity is 5 MW/km^2, or 3% of the total surface area. In this research, all solar panels face South at an angle of 35 degrees (Hörsch, Hofmann, et al., 2018). It is assumed that 50% of the solar power is utility-scale and 50% is rooftop solar power[46].

Hydroelectricity capacities are categorized into run-of-river, reservoir, and pumped hydro storage. Existing hydroelectric capacities are taken from the powerplantmatching database, which is a package that incorporates openly available power plant datasets (Gotzens et al., 2019). The energy storage capacities of the

[44] The fuel cells use green hydrogen in this study.

[45] A greenfield optimization means that existing solar and wind capacities are not included in the model, and sunk costs of existing capacities are disregarded.

[46] This information is embedded in the code of PyPSA-Eur.

reservoir and pumped hydro-storage technologies are estimated by distributing the country-aggregated storage capacities in proportion to its power capacity (Hörsch, Hofmann, et al., 2018). Run-of-river and reservoir hydro capacities receive an hourly-resolved in-flow of energy and pumped hydro-storage is used for load-balancing purposes (Hörsch, Hofmann, et al., 2018). Extensions to the current hydropower capacities are not considered.

Nuclear power plants are also extendable in the model. Extendable means that the capacity of nuclear power plants is determined in the optimization. It is assumed that all existing nuclear power plants will be phased out in 2040. New nuclear power capacity is based on the 3rd generation and is built at existing locations in the model. This means that in the Netherlands, new nuclear power capacity will be installed in Borsele. An efficiency of 33.7% is assumed for nuclear power plants. Lastly, fuel cells with an efficiency of 58% will be used to burn green hydrogen for electricity generation. In the modeling, there is only a cost difference between fuel cells and combined cycle gas turbines (CCGT), and these generation technologies are modeled similarly.

Table 14: capacity constraints of onshore wind power and the capacity of non-extendable power plants in the North Sea countries.

Country	Onshore wind capacity constraint [MW]	Hydro-electric capacity with reservoir [MW]	Run-of-river capacity [MW]	Pumped-hydro capacity [MW]
Belgium (Directorate-General for Energy, 2021c)	6600	13	59	1308
Denmark (The Danish Government's climate partnerships, 2020, p.52)	14500	0	0	0
France (Directorate-General for Energy, 2021c)	50700	8337	6989	4976
Germany (KNE, 2021)	105000	190	2877	7096
Ireland (Directorate-General for Energy, 2021a)	8200	1	216	392
Luxembourg (le Gouvernement Du Grand-Duché de Luxembourg, 2018, p,189)	550	0	31	2582
Netherlands (PBL, 2021)	8000	0	0	0
Norway (DNV GL, 2021, p.33)	11400	30971	424	282
Sweden (Thema Consulting Group, 2021, p.5)	32000	11979	1888	92
United Kingdom (Bose, 2021)	33000	203	1482	2600

5.6. Transmission system infrastructure

The existing transmission network capacities and topology for the ENTSO-E area were taken from the GridKit extraction from May 25, 2018, of the ENTSO-E interactive map of the European power system (Hörsch & Wiegmans, 2020). All voltage levels of the transmission network are mapped to the 380 kV level. Univalent nodes are removed sequentially until no univalent nodes exist. Further, HVDC lines in series or parallel are simplified to a single line l (Frysztacki et al., 2021, p.4). Simultaneous expansion of transmission lines and HVDC links is allowed up to the transmission volume cap.

5.7. Electricity storage

The electricity storage technologies used in this research are pumped-storage hydropower, batteries, and hydrogen storage. The model contains two extendable storage units: hydrogen and batteries. It is assumed that pumped-hydro energy storage has a round-trip efficiency of 75%, batteries have a round-trip efficiency of 81%, and hydrogen energy storage has a round-trip efficiency of 46%. Salt caverns are used for hydrogen storage, and fuel cells are used to combust hydrogen to produce electricity (Brown et al. 2018, p.4)

The energy capacity of energy storage units is proportional to their power capacity (Hörsch & Brown, 2017, p.4). This is given by the following equation:

$$H_{i,s}^{store} = h_{\max\_s} \cdot G_{i,s} \tag{20}$$

Where the factor $h_{\max\_s}$ shapes the time for charging or discharging the storage completely at maximum power. The factor $h_{\max\_s}$ is set at 6 hours for battery storage, 6 hours for pumped storage hydropower, and at 168 hours for hydrogen storage.

5.8. Technology cost assumptions

An important part of the investments in the energy system will be made between 2030 and 2040 since the temporal scope of this research is set at 2040. Hence, it is chosen to use the technology cost assumptions for 2030. Furthermore, a discount rate of 7% is used. An exception is rooftop solar, which uses a discount rate of 4%. The documented dataset provided by (Hörsch, Hofmann, et al., 2018) is used for the technology cost assumptions. The technology costs of power generation technologies are shown in Table 38. The technology cost of energy storage technologies is shown in Table 39, and the technology cost assumptions of transmission infrastructure technologies are shown in Table 40. The electricity costs of hydrogen energy storage are substantially lower because salt cavern storage is assumed instead of steel tank storage. The technology costs of salt caverns can be found in (Cihlar et al., 2021). The technical lifetime of salt caverns is assumed to be 40 years because hydrogen has been stored in a salt cavern at Teesside in the UK for nearly 50 years (Cihlar et al., 2021, p.43).

5.9. Modeling assumptions of the baseline scenario

The modeling assumptions of the baseline scenario are described in this section. Various parameters are changed in the experimental section, and the effect of changing these parameters is analyzed using the baseline scenario as a reference. Subsequently, the effect of changing these parameters on the Dutch demand for offshore wind capacity will be analyzed to explore the system effects of deploying much onshore wind in the North Sea. Table 15 presents an overview of the parameter settings of the baseline scenario.

The scenario-specific input parameters are electricity demand, technology costs, and extendable components. The electricity demand refers to the electricity load time series that needs to be matched by electricity generation every hour. The North Sea countries' electric load in the baseline scenario is shown in Table 13. The final aggregate electricity demand of the North Sea countries is 195 TWh. The electricity demand is between the estimated bandwidth of 177 and 270 TWh in 2050 when electricity consumption for green hydrogen is excluded, as is discussed in section 4.10.

The extendable components relate to the generators, storage, and transmission line capacities that are subject to optimization and are determined in the cost minimization. The extendable power plants in the baseline scenario are onshore wind, offshore wind, and solar PV. The non-extendable components in the baseline scenario are hydroelectric power plants. However, nuclear power plants are not part of the baseline scenario. In addition to the pumped-storage hydropower installed today, the model may build battery storage and hydrogen storage units at every bus. Further, the HVAC and HVDC transmission lines can be expanded in the optimization. The technology costs and characteristics relate to the fixed and variable costs of the extendable components. An overview of the technology cost assumptions in the baseline scenario is shown in Table 38, Table 39, and Table 40 of Appendix H.

Table 15: overview of scenario-specific settings used in the baseline scenario.

Parameter	Baseline scenario
Inputs	
1. Electricity demand	Load is taken from the TYNDP 2022 Global Ambition scenario for 2040.
2. Extendable components	Power plants: Onshore wind, offshore wind and solar PV. No nuclear power plants. Storage: batteries and hydrogen storage. Transmission lines: HVAC and HVDC.
3. Technology costs and characteristics	No amendments. An overview of the technology costs assumptions is shown in Table 38, Table 39, and Table 40.
Constraints	
4. CO_2 reduction constraint	CO_2 reduction of 100% CO_2 relative to 1990
5. Generator capacity constraints	Onshore wind power capacity constraint. The onshore wind capacity constraints in place are shown in Table 14.
6. Transmission line expansion limit	The size of the electricity transmission system can be expanded to maximum 150% of the current electricity transmission system.
7. Minimal domestic production constraint	Each country produces at least 80% of its electricity demand domestically.
8. Storage operation limits	The storage operation limits are 6, 6, and 168 hours for battery storage, pumped-storage hydropower, and hydrogen storage, respectively.

The optimization problem is also subject to various constraints. The scenario-specific constraints are the CO_2 reduction constraint, the generator capacity constraints, the transmission line expansion constraints, the minimal domestic production constraints, and the storage operation limits. The absolute CO_2 reduction limit relates to the electric power system's maximum allowed carbon dioxide emissions, which is set to zero CO_2 emissions in the baseline scenario.

The generator capacity constraints limit energy generation technologies' minimum or maximum capacity. Since the support for onshore wind power is limited, an onshore wind constraint is set in each country in the baseline scenario. Table 14 shows an overview of the set onshore wind capacity constraints. Similarly, the transmission line expansion limit specifies the limits on line expansion for the optimization model. The transmission line expansion limit in the baseline scenario is set to 150%[47] of the installed capacity in 2018.

Furthermore, similar to Neumann (2021) and Parzen et al., (2022), an equity constraint is included that obliges each country to produce at least 80% of its total electricity demand. This leads to a smooth distribution of power plants across Europe and prevents European member states from becoming too dependent on electricity imports from neighboring countries. Lastly, the storage operation limits determine the maximum state of charge capacity of a storage unit in terms of hours at full output capacity. It is assumed that the storage operation limits are 6 hours for battery storage, 6 hours for pumped-storage hydropower, and 168 hours for hydrogen storage in the baseline scenario.

[47] TNO 2022 assumes an electricity interconnection expansion of 200% in both scenarios (Scheepers et al., 2022, p.19) in 2040. Hence, a maximum expansion of 150% of its size in 2018 is assumed reasonable.

5.10. Experimental setup

This section formulated scenarios to explore the energy system effects of installing many offshore wind turbines in the North Sea. Table 16 shows an overview of the scenarios used in the experiments. One parameter will be changed in each scenario relative to the baseline scenario. The scenarios are formulated based on the results of the scenario analysis in chapter 4. First, the link between the scenarios in the experiments and the scenario analysis is discussed. After that, the scenarios are described in detail.

Table 16: description of the various scenarios.

Scenario	Parameter	Change from the baseline scenario
Scenario 1	6. Transmission line expansion limit	The size of the electricity transmission system cannot be expanded.
Scenario 2	6. Transmission line expansion limit	The size of the transmission capacity will be optimized in terms of costs and volume.
Scenario 3	7. Minimal domestic production	There is no domestic electricity generation constraint.
Scenario 4	1. Electricity demand	The electricity demand of the Netherlands will be 243 TWh.
Scenario 5	1. Electricity demand	The electricity demand of the Netherlands will be 386 TWh.
Scenario 6	1. Electricity demand	The electricity demand of the Netherlands will be 544 TWh.
Scenario 7	2. Extendable components	Nuclear power plants will be built in the Netherlands.
Scenario 8	2. Extendable components	Nuclear power plants will be built in the Netherlands, France and the UK.
Scenario 9	2. Extendable components	The number of nuclear power plants in 2013 will be operating.
Scenario 10	5. Generator capacity limit	Solar power capacity in the Netherlands will be set at 30 GW.
Scenario 11	5. Generator capacity limit	Solar power capacity in the Netherlands will be set at 60 GW.
Scenario 12	5. Generator capacity limit	Solar power capacity in the Netherlands will be set at 120 GW.
Scenario 13	2. Technology costs and characteristics	Tank storage will be used to store hydrogen instead of salt caverns.
Scenario 14	5. Generator capacity limit	The onshore wind capacity constraint in the Netherlands will be set at 20 GW, instead of 8 GW.
Scenario 15	3. Technology costs and characteristics	The capital costs of offshore wind turbines is the same as the capital costs of onshore wind turbines (-36.6%).
Scenario 16	2. Extendable components	Green hydrogen can be imported from outside the North Sea countries. The hydrogen price is 60 EUR/MWh.
Scenario 17	2. Extendable components	Green hydrogen can be imported from outside the North Sea countries. The hydrogen price is 45 EUR/MWh.
Scenario 18	2. Extendable components	Green hydrogen can be imported outside the North Sea countries The hydrogen price is 45 EUR/MWh with a supply constraint of 270 TWh.
Scenario 19	1. Electricity demand	The electricity demand of the North Sea countries, except the Netherlands, is increased by 10%.
Scenario 20	1. Electricity demand	The electricity demand of the North Sea countries, except the Netherlands, is increased by 25%.
Scenario 21	1. Electricity demand	The electricity demand of the North Sea countries, except the Netherlands, is increased by 50%.
Scenario 22	3. Technology costs and characteristics	The onshore wind power capacity constraint is doubled in neighboring countries.
Scenario 23	3. Technology costs and characteristics	Solar power capacity is 50% higher in neighboring countries.
Scenario 24	3. Technology costs and characteristics	Offshore wind capacity is higher in neighboring countries.

5.10.1. Link scenarios in experiments with scenario analysis.

This section describes the link between the formulated scenarios in the experimental section and the results of the scenario analysis in chapter 4. A relation was found in the scenario analysis between Dutch electricity demand and offshore wind capacity in the Netherlands. Hence, the influence of changing domestic electricity demand in the Netherlands on offshore wind deployment in the Netherlands is investigated. Hence, in the fourth scenario, the electricity demand in the Netherlands is 243 TWh. The latter is the electricity demand in the Regional Steering scenario of the II3050. In the fifth scenario, the electricity demand in the Netherlands increases to 386 TWh, which is the electricity demand in the KEV 2020 scenario study. In the sixth scenario, Dutch electricity demand increases to 544 TWh, which is the electricity demand of the Netherlands in the TRANSFORM scenario in TNO 2022.

Furthermore, nuclear power plants are included in the ADAPT scenario of TNO 2022. The effect of installing nuclear power plants in the Netherlands is examined in scenario 7. Scenario 8 investigated the effect of new nuclear power plants on offshore wind capacity deployment when the Netherlands, France, and the United Kingdom built new nuclear power plants. The installed solar capacity in the Netherlands ranged from 389 to 125 GW in the examined scenario studies. Hence, the effect is investigated in scenarios 10, 11, and 12. Similarly, the effect of more onshore wind capacity in the Netherlands is examined in scenario 14.

Lastly, in the European Steering scenario of the II3050, hydrogen is used as a fuel for electricity generation, as is shown in Table 4. The effect of hydrogen imports for electricity generation on offshore wind deployment in the Netherlands is investigated in scenarios 16, 17, and 18.

5.10.2. Detailed description of the scenarios

The effect of transmission system expansion will be investigated in the first three scenarios. In the first scenario, the transmission system is not allowed to expand, and the transmission system will have the same size as it had in 2018. In the second scenario, the transmission system expansion is limited to 50% of its size in 2018.. Individual lines are allowed to be expanded by more than 50%. However, the total transmission system expansion should be equal to or less than 50% of its size in 2018. In the third scenario, the constraint of 80% domestic electricity generation is lifted, and countries can import as much electricity as it needs. The grid expansion in the third scenario is constrained to 150% of its size in 2018.

In scenarios four, five, and six, the electricity demand of the Netherlands is increased. The electric load of the Netherlands increases to 243 TWh in scenario 4, 386 TWh in scenario 5, and 544 TWh in scenario 6. The electric load in scenarios 4,5, and 6 are obtained by linearly scaling the load profiles of the Global Ambition scenario in 2040 of the TYNDP 2022.

In scenarios seven, eight, and nine, the effect of nuclear power plants on Dutch offshore wind power demand is examined. An overview of the power plants in the North Sea countries in scenarios seven, eight, and nine are shown in Table 17. In the seventh scenario, a 3.5 GW new nuclear power plant capacity will be built in Borsele, a town in the Netherlands. A new nuclear power capacity of 3.5 GW is part of the vision of EPZ (EPZ, 2020), which is the company that operates the existing nuclear power plant in Borsele. In addition, the British and French governments also have ambitions to build new nuclear power plants. The government of the United Kingdom has set an ambition of 24 GW of new nuclear capacity by 2050 (Stevens, 2022). Nuclear power plants currently deliver most of the electricity in France. However, existing nuclear power plants are beginning to age, and it is uncertain what France's nuclear capacity will be. It is assumed that France will have 27 GW of new nuclear capacity in 2040. This is based on the NO3 scenario of a scenario report conducted by France's TSO (Réseau de Transport d'Électricité, 2021, p.17). In scenario 9, it is assumed that existing nuclear power plants in the North Sea countries are newly built. This means that each North Sea country has the same nuclear power plant capacity as in 2020. Existing nuclear power plant capacities are taken from the powerplantmatching database (Gotzens et al., 2019).

Table 17: nuclear power plant capacity in scenarios seven, eight, and nine.

Country	Nuclear power plant capacity scenario 7 [MW]	Nuclear power plant capacity scenario 8 [MW]	Nuclear power plant capacity scenario 9 [MW]
Belgium	0	0	5919
Denmark	0	0	0
France	0	27000	63130
Germany	0	0	9314
Ireland	0	0	0
Luxembourg	0	0	0
Netherlands	3500	3500	485
Norway	0	0	0
Sweden	0	0	8617
United Kingdom	0	24000	9314

The amount of solar capacity in the Netherlands in future energy scenarios ranges from 38 GW to 132 GW in 2050 (see Table 10). In scenarios ten, eleven, and twelve, the effect of different solar power capacities in the Netherlands on the energy system will be examined. The solar power capacity is 30 GW in the tenth scenario, 60 GW in the eleventh scenario, and 120 GW in the twelfth scenario.

In the thirteenth scenario, tank storage will be used to store hydrogen instead of salt caverns. Tank storage is more expansive than salt caverns, as can be seen in Table 39. This scenario is run because the cost assumptions of hydrogen storage in steel tanks are used in literature that used PyPSA-Eur (Hörsch, Hofmann, et al., 2018; Schlachtberger et al., 2017). In the fourteenth scenario, the onshore wind power constraint in the Netherlands will be raised from 8 GW to 20 GW. Subsequently, the effect of a higher onshore wind constraint on the offshore wind capacity in the Netherlands can be examined. In the fifteenth scenario, the assumed investment costs of offshore wind turbines are 36.6% lower. As a result, offshore wind turbines will have the same capital costs as onshore wind turbines.

In scenarios 16, 17, and 18, green hydrogen can be imported for electricity generation from outside the North Sea countries. Regions with significant hydrogen potential are, for instance, North Africa and Ukraine (Wang et al., 2021, p.7). Green hydrogen import can be used as an alternative to domestic hydrogen storage. The effect of different import prices and volumes on the electricity system is also investigated in these scenarios. In the sixteenth and seventeenth scenarios, green hydrogen can be imported for 60 EUR/MWh and 45 EUR/MWh, respectively. In the eighteenth scenario, a maximum of 270 TWh of green hydrogen can be imported for 45 EUR/MWh outside the North Sea countries.

The effect of higher electricity demand in the neighboring countries of the Netherlands is investigated in scenarios 19, 20, and 21. In the nineteenth scenario, the electricity demand of Germany, the UK, France, Belgium, Sweden, Norway, and Ireland is 10% higher. The electricity demand in Luxembourg stays the same as in the baseline scenario because the electricity demand in Luxembourg already increased sharply in the Global Ambition scenario of the TYNDP 2022 in 2040. Since Luxembourg is a small land-locked country, the onshore wind power constraint and the domestic electricity generation constraint of 80% would lead to excessive amounts of solar power capacity in Luxembourg. In the twentieth scenario, electricity demand increases by 25%, and electricity demand increases by 50% in the twenty-first scenario. An overview of electricity demand in scenarios 19, 20, and 21 is displayed in Table 18.

Table 18: electricity demand of the North Sea countries in scenario 19, 20 and 21.

Country	Electricity demand Baseline scenario [TWh]	Scenario 19: 10% higher electricity demand [TWh]	Scenario 20: 25% higher electricity demand [TWh]	Scenario 21: 50% higher electricity demand [TWh]
Belgium	109	120	136	164
Denmark	60	66	75	90
France	620	682	775	930
Germany	773	850	966	1159
Ireland	46	51	58	69
Luxembourg	13	13	13	13
Netherlands	195	195	195	195
Norway	181	200	227	272
Sweden	162	178	203	243
United Kingdom	552	607	689	827

The effect of specifically set capacities of onshore wind, solar PV, and offshore wind is investigated in scenarios 22, 23, and 24, respectively. Table 19 shows an overview of the modified capacity constraints. The onshore wind capacity constraint is relaxed in neighboring countries of the Netherlands in scenario 22. In scenario 23, the minimum solar PV capacities in the system are increased in Belgium, Denmark, France, Germany, Ireland, Sweden, Norway, and the UK, by 50% relative to the optimum amount of solar power capacity in the baseline scenario[48]. Lastly, the effect of a higher offshore wind capacity in bordering countries of the Netherlands is investigated in scenario 24. Each country's minimum offshore wind capacity in scenario 24 is based on national offshore wind power targets.

Table 19: modified capacity constraints for scenario 22, 23 and 24.

Country	Scenario 22: onshore wind capacity constraint [MW]	Scenario 23: minimum solar PV capacity in neighboring countries[49] [MW]	Scenario 24: minimum offshore wind capacity in each country [MW]
Belgium	13200	8470	8000 (Wind Europe, 2022a)
Denmark	29000	1950	40000 (The Danish Government's climate partnerships, 2020, p.77)
France	101400	211818	40000 (Wind Europe, 2022b)
Germany	210000	210294	70000 (Prognos et al., 2020, p.22)
Ireland	16400	80	35000 (Wind Europe, 2021)
Luxembourg	1100	10074	0
Netherlands	8000	10213	0
Norway	22800	228	30000 (Wind Europe, 2022c)
Sweden	64000	9865	41000 (Thema Consulting Group, 2021, p.1)
United Kingdom	66000	53247	100000 (Morales, 2022)

[48] An alternative method would be to set a minimum overall solar PV capacity in the system instead of minimum capacities per country.

[49] The minimum amount of solar PV in Luxembourg is the same as in the modeling results of the baseline scenario.

6. Results power system modeling

This chapter presents the results of the power system modeling. Section 6.1 discusses the modeling outcomes of the baseline scenario. In section 6.2, a sensitivity analysis is conducted to examine how the temporal resolution, the number of nodes in the power system network, and the electric load curve influence the modeling outcomes of the baseline scenario. Section 6.3 compares the baseline scenario to a study that used the PyPSA-Eur model to validate this thesis' model. Further, sections 6.4 to 6.11 present the results of the scenarios, as described in Table 16. Lastly, the findings of the modeling are presented in section 6.12.

6.1. Results baseline scenario and validation of the model outcomes

This section presents the results of the baseline scenario. The results of the baseline scenario are shown in Table 20. First, it can be observed that the electricity generation in the system is 2953 TWh, and the electric load of the North Sea countries is 2711 TWh in the baseline scenario in 2040. This means that 242 TWh can be attributed to losses due to energy storage. The total system costs in the North Sea countries are 131.44 billion euros, corresponding to an average costs of electricity of 48.1 EUR/MWh. The load duration curve of the baseline scenario is shown in Figure 11 and Figure 12 of Appendix C. The transmission system expansion of the baseline scenario is 98% of the size of the transmission system in 2018. Moreover, the North Sea countries are not dependent on energy imports because the energy system is entirely renewable and does not require fuels from outside the North Sea countries.

Furthermore, the electricity generation in the Netherlands is 219 TWh, and the net electricity export to bordering countries is 7 TWh. The HVAC expansion is 186% compared to the capacity of HVAC lines in 2018, but the HVDC lines in the Netherlands are not expanded in the baseline scenario[50]. The onshore wind capacity in the Netherlands is 8 GW, equal to the onshore wind constraint. The optimal solar PV capacity in the baseline scenario is 10.2 GW, less than currently installed[51]. The offshore wind capacity in the baseline scenario is 42 GW, of which 15.7 GW is near-shore capacity, and 26.3 GW is further away than 30 km from the Dutch shore. The amount of onshore and offshore wind capacities in the baseline scenario is similar to that in the ADAPT scenario of TNO 2022. However, the amount of solar power capacity in ADAPT is much higher than in the baseline scenario. The power plants in the Netherlands have the following capacity factors: onshore wind has a capacity factor of 38.6%, solar PV has a capacity factor of 9.7%, offshore wind connected via alternating current lines has a capacity factor of 42.6%, and offshore wind connected via direct current has a capacity factor of 44.9%.

Next, the capacity factors of the baseline scenario are compared to the capacity factors in energy scenario studies of the Netherlands, as shown in Table 12. The capacity factor of solar PV is equal to the capacity factor of solar PV in the II3050 and TNO 2022 but lower than the capacity factor in the KEV 2021, KIVI 2020, and TYNDP 2022. The capacity factor of onshore wind in the baseline scenario is lower than the capacity factor of onshore wind in TNO 2022 but higher than the capacity factors in other energy scenario studies, which ranges from 25% in the International Steering scenario in the II3050 to 33% in KEV 2022. Finally, the capacity factor of offshore wind power in the baseline scenario is on the low end since it has the same capacity factor as in the scenarios of the II3050. Approximately 3% of the electricity produced by offshore wind turbines

[50] The capacity of HVDC lines is expanded in other countries. However, the capacity of HVDC lines in the Netherlands keeps the same capacity in the baseline scenario. Only HVDC lines between nodes are displayed, and the required infrastructure to link new power plants to a node is not included in this number.

[51] The solar power capacity in the Netherlands reached 11 GW in 2021 (PBL, 2021, p.105).

is curtailed (see Table 35), and the capacity factors without curtailment is 43.9% for wind turbines connected via AC line s and 46.4% for offshore wind turbines connected via DC lines10. Additionally, the onshore wind capacity factor is on the high end, and the average capacity of all North Sea countries in the baseline scenario is 32.1%. This implies that the onshore wind turbines in the Netherlands are placed in favorable locations with high wind speeds.

Table 20: results of the baseline scenario.

	Unit	Baseline scenario
General statistics electric power system of the North Sea countries		
Electrical load	TWh	2711
Electricity generation	TWh	2953
Electricity usage for energy storage	TWh	242
Transmission capacity expansion relative to existing grid	%	98
Total annual system costs North Sea countries	B. EUR/ year	130.4
Electricity costs per MWh	EUR/MWh	48.1
Import dependency as percentage of total electricity generation	%	0
Transmission system statistics of the Netherlands		
Electrical load	TWh	195
Electricity generation	TWh	219
Net electricity export	TWh	7
HVAC expansion	%	186
HVDC expansion	%	0
Power generation statistics of the Netherlands		
Capacity onshore wind	GW	8.0
Capacity offshore wind	GW	42.0
Capacity offshore wind-ac	GW	15.7
Capacity offshore wind-dc	GW	26.3
Capacity solar PV	GW	10.2
Capacity nuclear power plants	GW	0
Production onshore wind	TWh	30.9
Production offshore wind	TWh	178.4
Production solar PV	TWh	9.7
Production nuclear power plants	TWh	0
Power system flexibility statistics of the Netherlands		
Hydrogen storage capacity	TWh	4.0
Electrolysis capacity	GW	10.1
Fuel cell capacity	GW	31.6
Electricity consumption hydrolysis	TWh	31.1
Electricity generation fuel cells	TWh	14.5
Battery storage capacity	MWh	1.1
Battery charge capacity	MW	0.3
Battery discharge capacity	MW	0.4
Electricity consumption batteries	GWh	0.8
Electricity generation batteries	GWh	0.6

6.2. Sensitivity analysis baseline scenario

In this section, sensitivity analyses are performed to see how the number of nodes and the hourly resolution of the model influence the model outcomes of the baseline scenario. Further, it is investigated whether there is a substantial difference in model outcomes between the electric load of the Global Ambition scenario in 2040 of the TYNDP 2022 and the linearly scaled historic load of 2013.

6.2.1. Sensitivity temporal resolution

The effect of the hourly resolution on the modeling outcomes of the baseline scenario is shown in Table 21. The baseline scenario is run with a 1-hourly resolution, a 2-hourly resolution, a 3-hourly resolution, and a 4-hourly resolution. When the temporal resolution is increased from a 3-hourly to an hourly model, there is no noticeable difference in aggregated electricity generation and transmission system expansion in the North Sea countries of the baseline scenario. The total system costs are the highest in the 1-hourly resolution model and the lowest in the 4-hourly resolution model. This means that the baseline model with a lower temporal resolution could slightly underestimate the annual system costs of the electricity system of the North sea counties. A shift from a 3-hourly resolution to an hourly resolution also leads to slightly more solar energy and less wind energy in the system, as is shown in Table 36. The literature has also observed an increase in the share of solar power generation when a 3-hourly resolution is used (Schlachtberger et al., 2018, p.15).

Furthermore, it can be observed that electricity generation in the Netherlands is the highest in the 1-hourly resolution model and the lowest in the 4-hourly resolution model. The solar power and onshore wind capacities are the same in the four scenarios with different temporal resolutions. The offshore wind capacity in the Netherlands is higher in the baseline scenario with an hourly temporal resolution. More electricity export by the Netherlands causes the higher offshore wind capacity because the electric load in the Netherlands stays constant in each scenario.

Electricity storage in the Netherlands also changes with temporal resolution. The larger hydrogen storage in the 1-hourly model is correlated with the extra offshore wind capacity in the 1-hourly model. However, the hydrogen storage capacity in the 4-hourly model is considerably smaller than in the other models. These effects are even larger for battery storage. Battery storage capacity is the highest in the 1-hourly resolution model and is an order of magnitude smaller in the 2-hourly and 3-hourly models. Battery storage capacity in the 4-hourly model is roughly two times higher than in the 2-hourly and 3-hourly models but lower in the 1-hourly resolution model, which means that the temporal resolution of the model has a considerable influence on the battery capacities in the model. This can be explained as follows: the temporal averaging in the 2-hourly, 3-hourly, and 4-hourly models implicitly simulates the smoothing effect of short-term battery storage, which becomes apparent in the reduced battery storage in the model. The temporal smoothing effect is much smaller with wind energy because the dominant wind fluctuations occur at larger time scales (Schlachtberger et al., 2018, p.7).

Table 21: 40-nodes baseline scenarios with different hourly resolutions.

	Unit	1-hourly resolution	2-hourly resolution	3-hourly resolution	4-hourly resolution
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2711	2711	2711
Electricity generation	TWh	2955	2955	2953	2952
Electricity usage for energy storage	TWh	244	244	242	241
Transmission capacity expansion relative to existing grid	%	99	98	98	102
Total annual system costs North Sea countries	B. EUR/ year	131.0	130.8	130.4	130.0
Electricity costs per MWh	EUR/MWh	48.3	48.2	48.1	48.0
Import dependency as percentage of total electricity generation	%	0	0	0	0
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	195	195
Electricity generation	TWh	227	219	219	209
Net electricity export	TWh	15	7	7	0
HVAC expansion	%	191	188	186	188
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.8	42.1	42.0	39.0
Capacity offshore wind-ac	GW	15.7	15.7	15.7	15.7
Capacity offshore wind-dc	GW	27.1	26.4	26.3	23.3
Capacity solar PV	GW	10.2	10.2	10.2	10.2
Capacity nuclear power plants	GW	0	0	0	0
Production onshore wind	TWh	30.9	30.9	30.9	30.9
Production offshore wind	TWh	186.7	178.3	178.4	168.3
Production solar PV	TWh	9.7	9.7	9.7	9.7
Production nuclear power plants	TWh	0	0	0	0
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.2	4.2	4.0	3.5
Electrolysis capacity	GW	10.6	10.3	10.1	8.6
Fuel cell capacity	GW	33.7	33.9	31.6	27.0
Electricity consumption hydrolysis	TWh	32.7	31.8	31.1	26.4
Electricity generation fuel cells	TWh	15.2	14.8	14.5	12.2
Battery storage capacity	MWh	9.8	1.0	1.1	2.6
Battery charge capacity	MW	8.8	0.5	0.3	0.6
Battery discharge capacity	MW	9.7	0.5	0.4	0.7
Electricity consumption batteries	GWh	11.1	0.9	0.8	1.6
Electricity generation batteries	GWh	9.8	0.7	0.6	1.3

6.2.2. Sensitivity spatial resolution

In order to examine the effect of the number of nodes on the modeling outcomes, the baseline scenario is run with 30 nodes, 40 nodes, 60 nodes, and 80 nodes in the power system network. The results are shown in Table 22.

When the spatial resolution is increased from 30 to 80 nodes, the electricity generation in the North Sea countries decreases from 2961 TWh to 2942 TWh. The transmission system expansion relative to the existing grid increases from 88% in the 30-nodes model to 101% in the 80 nodes-model. However, the transmission system expansion does not scale linearly with the number of nodes because the transmission system expansion in the 60-nodes model is lower than the transmission system expansion in the 40-nodes model and 80-nodes model. Moreover, the annual electricity system cost is 131 billion euros in the 30-nodes model, and the annual electricity system costs decrease linearly to 129 billion euros in the 80-nodes model. Hence, a higher spatial resolution increases annual system costs, while a higher temporal resolution decreases annual total system costs. This can be explained as follows: higher costs are driven by the network bottlenecks revealed at higher resolutions, limiting access to wind and solar sites with high capacity factors. On the other hand, a higher resolution reveals more advantageous onshore wind sites, which changes the balance of energy generation technologies (Frysztacki et al., 2021).

In addition, electricity generation in the Netherlands is 227 TWh in the 30-nodes model, and electricity generation decreases to 209 TWh in the 80-nodes model. Net electricity exports of the Netherlands are 11 TWh in the 30-nodes model, and the electricity exports of the Netherlands decrease to -9 TWh in the 80-nodes model. The offshore wind capacities in the Netherlands correspond to the electricity exports, and the offshore wind capacity is the highest in the 30-nodes model and the highest in the 80-nodes model. The offshore wind capacity is 42.8 GW in the 30-nodes model and 39 GW in the 80-nodes model. This implies that a higher number of nodes in the power system network results in fewer electricity exports from the Netherlands.

Hydrogen storage capacity, fuel cell capacity, and electrolyzer capacity are the highest in the 30-nodes model and the lowest in the 80-nodes model. The battery storage capacities do not differ substantially between the models with different spatial resolutions. Therefore, hydrogen storage in the Netherlands increases with a higher temporal resolution and decreases with a higher spatial resolution.

Table 22: baseline scenario with different spatial resolutions.

	Unit	30-nodes model	40-nodes model	60-nodes model	80-nodes model
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2711	2711	2711
Electricity generation	TWh	2961	2953	2947	2942
Electricity usage for energy storage	TWh	250	242	236	232
Transmission capacity expansion relative to existing grid	%	88	98	94	101
Total annual system costs North Sea countries	B. EUR/ year	131.8	130.4	129.6	128.8
Electricity costs per MWh	EUR/MWh	48.6	48.1	47.8	47.5
Import dependency as percentage of total electricity generation	%	0	0	0	0
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	195	195
Electricity generation	TWh	224	219	214	199
Net electricity export	TWh	11	7	4	-9
HVAC expansion	%	120	186	193	191
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.4	42.0	38.7	35.5
Capacity offshore wind-ac	GW	15.7	15.7	10.0	9.2
Capacity offshore wind-dc	GW	26.7	26.3	28.6	26.3
Capacity solar PV	GW	10.2	10.2	10.2	10.2
Capacity nuclear power plants	GW	0	0	0	0
Production onshore wind	TWh	30.6	30.9	32.3	32.4
Production offshore wind	TWh	183.9	178.4	171.7	156.5
Production solar PV	TWh	9.7	9.7	9.7	9.7
Production nuclear power plants	TWh	0	0	0	0
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.2	4.0	3.5	3.0
Electrolysis capacity	GW	10.8	10.1	9.0	7.6
Fuel cell capacity	GW	36.0	31.6	32.3	30.9
Electricity consumption hydrolysis	TWh	33.9	31.1	27.5	23.3
Electricity generation fuel cells	TWh	15.7	14.5	12.8	10.8
Battery storage capacity	MWh	1.4	1.1	1.6	1.6
Battery charge capacity	MW	0.4	0.3	0.5	0.5
Battery discharge capacity	MW	0.5	0.4	0.5	0.5
Electricity consumption batteries	GWh	1.0	0.8	1.1	1.1
Electricity generation batteries	GWh	0.8	0.6	0.9	0.9

6.2.3. Effect of the electric load curve shapes

This section examines the effect of the load profiles' shape on the modeling outcomes. The results of the different shapes of the electric load curves are shown in Table 23. Model 1 uses the load profile of the Global Ambition scenario of the TYNDP 2022 in 2040. In model 2, the historic load of the North Sea countries in 2013 is linearly scaled to 2711 TWh. The load curves are illustrated in Figure 11 and Figure 12 of Appendix B. Both models use the settings of the baseline scenario as described in Table 15.

First, it can be observed that energy storage's electricity consumption in the North Sea countries is 2953 TWh in model 1 and 2970 TWh higher in model 2. In addition, the optimal transmission system expansion and the total annual system costs of the electric power system in the North Sea countries are higher in model 2 than in model 1. In addition, the electricity usage for energy storage is higher in model 2 than in model 1. The difference in electricity consumption, energy storage, and transmission expansion in the North Sea countries between model 1 and model 2 can be explained by a higher flexibility requirement in the electric power system in model 2 due to the higher peak loads in model 2.

Furthermore, electricity generation and exports of the Netherlands are lower in model 1 than in model 2. As a consequence, offshore wind capacity is lower in model 1 as well. The HVAC line expansion is higher in model 2 than in model 1. A potential explanation is that transmission system expansion is used for balancing supply and demand because the peak loads are higher in model 2 than in model 2.

Lastly, a large difference can be seen in the power system flexibility statistics of the Netherlands. The hydrogen storage capacity is 4.0 TWh in model 1 and 6.6 TWh in model 2. This means that more seasonal storage is required when electricity demand shows higher fluctuations during the year. Lastly, the electrolysis, fuel cell, and battery storage capacities remain roughly the same in both models.

Table 23: results of the baseline scenario with different electric load curves.

	Unit	Model 1: Load profile of the TYNDP 2022 Global Ambition scenario for 2040	Model 2: Linearly scaled historic load of 2013
General statistics electric power system of the North Sea countries			
Electrical load	TWh	2711	2711
Electricity generation	TWh	2953	2970
Electricity usage for energy storage	TWh	242	259
Transmission capacity expansion relative to existing grid	%	98	114
Total annual system costs North Sea countries	B. EUR/ year	130.4	133.5
Electricity costs per MWh	EUR/MWh	48.1	49.2
Import dependency as percentage of total electricity generation	%	0	0
Transmission system statistics of the Netherlands			
Electrical load	TWh	195	195
Electricity generation	TWh	219	212
Net electricity export	TWh	7	4
HVAC expansion	%	186	195
HVDC expansion	%	0	0
Power generation statistics of the Netherlands			
Capacity onshore wind	GW	8.0	8.0
Capacity offshore wind	GW	42.0	40.4
Capacity offshore wind-ac	GW	15.7	15.7
Capacity offshore wind-dc	GW	26.3	24.7
Capacity solar PV	GW	10.2	10.2
Capacity nuclear power plants	GW	0	0
Production onshore wind	TWh	30.9	30.9
Production offshore wind	TWh	178.4	171.8
Production solar PV	TWh	9.7	9.7
Production nuclear power plants	TWh	0	0
Power system flexibility statistics of the Netherlands			
Hydrogen storage capacity	TWh	4.0	6.6
Electrolysis capacity	GW	10.1	9.7
Fuel cell capacity	GW	31.6	32.8
Electricity consumption hydrolysis	TWh	31.1	31.2
Electricity generation fuel cells	TWh	14.5	14.5
Battery storage capacity	MWh	1.1	1.2
Battery charge capacity	MW	0.3	0.4
Battery discharge capacity	MW	0.4	0.4
Electricity consumption batteries	GWh	0.8	0.9
Electricity generation batteries	GWh	0.6	0.7

6.3. Comparison baseline scenario to Neumann and Brown (2021)

Neumann and Brown (2021) have investigated near-optimal feasible solutions for European renewable power systems using the PyPSA-Eur model. This study includes solar PV, onshore wind, offshore wind, and hydropower. Further, battery and hydrogen storage are used for dispatchable generation, and transmission capacity expansion is allowed. In the 100% CO_2 reduction scenario, the total system costs are 246 billion euros per year, and this corresponds to an average costs of electricity of 78.4 EUR/MWh (Neumann & Brown, 2021, p.4). The average costs of electricity in Europe in Neumann & Brown (2021) in the 100% CO_2 reduction scenario is much higher than the average in the baseline scenario, which also reaches zero CO_2 emissions. A significant difference between these scenarios is the technology used for hydrogen storage. Steel tank storage is used in Neumann & Brown (2021), whereas salt caverns are used in the baseline scenario. If hydrogen is stored in steel tank storage in the baseline scenario as well, holding everything else constant, the average costs of electricity increase to 58.56 EUR/MWh (see scenario 13 in Table 28).

Another important difference between the baseline scenario and Neumann and Brown (2021) is the techno-economic assumptions. The baseline scenario assumes investment costs of 1040 EUR/kW for onshore wind, 425 EUR/kW for utility-scale solar PV, and 1640 EUR/kW for offshore wind. In contrast, Neumann & Brown (2021) assumes investment costs of 1330 EUR/kW for onshore wind, 600 EUR/kW for utility-scale solar PV, and 1965 EUR/kW for offshore wind. Furthermore, in Neumann & Brown (2021), 5% of electricity is produced by hydropower. In the baseline scenario, 9% of electricity is produced by (Neumann & Brown, 2021, p.4). hydropower. Since it is assumed that existing power plants in PyPSA-Eur are amortized, a larger share of the electricity generation in the baseline scenario is not included in the annual system costs.

Figure 7 illustrates the baseline scenario's power plant capacities and the transmission system expansion in the North Sea countries. It can be observed that the majority of hydropower in the system is located in Norway. There is relatively much wind power capacity in the Northern countries, and there is relatively much solar capacity in the south of France and the south of Germany. There are also significant HVAC line expansions going from Denmark, through Germany, to France.

Further, the transmission line expansion and regional generator and storage capacities of the 100% CO_2 reduction scenario in Neumann & Brown (2021) are compared with the baseline scenario of this research. First, it can be observed that most of the solar power capacity in the baseline scenario is located in the south of Germany and the south of France. In contrast, most of the solar power capacity in Neumann & Brown (2021) is located around the Middle Sea (see Figure 8). There are more solar hours in the areas around the Middle Sea, which explains why solar capacity is located in these areas in Neumann & Brown (2021). There is also more onshore wind capacity in Neumann & Brown (2021 than in the baseline scenario. The lower onshore wind capacity in the baseline scenario can be explained by the onshore wind constraint that is active in the baseline scenario.

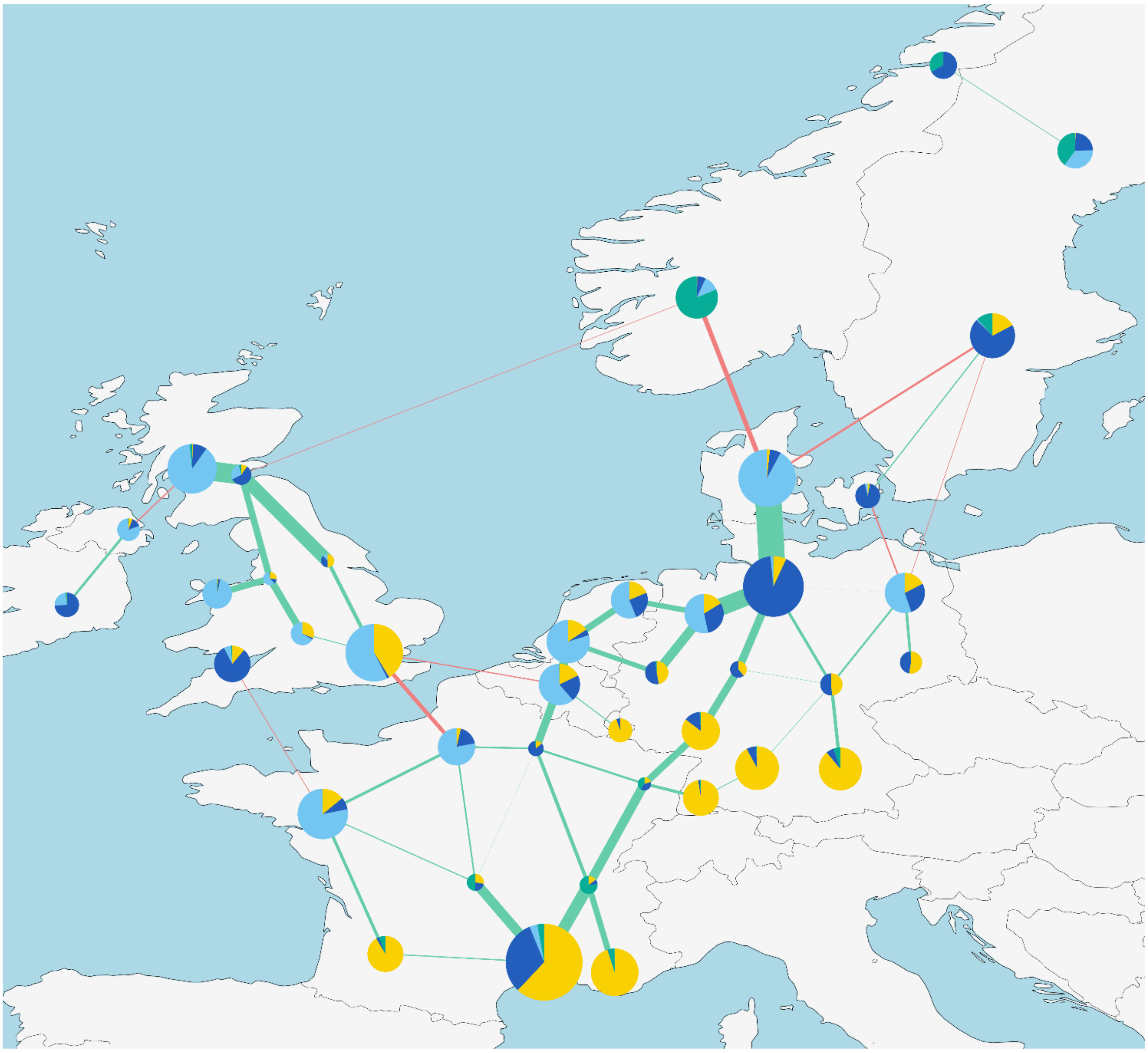

Figure 7: power plant capacity per node and transmission system expansion in the baseline scenario.

Moreover, there is more HVAC line expansion than HVDC line expansion in the baseline scenario, while the HVDC lines expansion is larger than the HVAC lines expansion in the study of Neumann & Brown (2021). There are multiple explanations. First, electricity demand in the baseline scenario has increased from 1869 TWh in 2013 to 2711 TWh in 2040, whereas electricity demand does not change substantially in Neumann & Brown (2021). When the electric load of the power system of the North Sea countries is increased, more transmission system capacity is required, which explains the large HVAC transmission system expansion in the baseline scenario (see Figure 7). Second, the cost-optimized solution when tank storage is used for hydrogen storage instead of salt caverns includes more expansion of HVDC lines. This is illustrated in Figure 17 of Appendix D. Third, renewable electricity generation in the west and southwest of Germany is relatively modest in both studies. However, populous states of Germany are located in the west and southwest of Germany, such as North Rhine-Westphalia and Baden-Württemberg, and the electricity demand in these scenarios increases by 50% in the baseline scenario (see Table 13). In the baseline scenario, electricity is transported from the north of Germany to the west and southwest of Germany. Further, Switzerland is not part of the system in the baseline scenario. As a result, (solar) electricity cannot be exported to the east of France and the south of Germany. In contrast, this possibility exists in the 100% CO_2 reduction scenario in Neumann & Brown (2021).

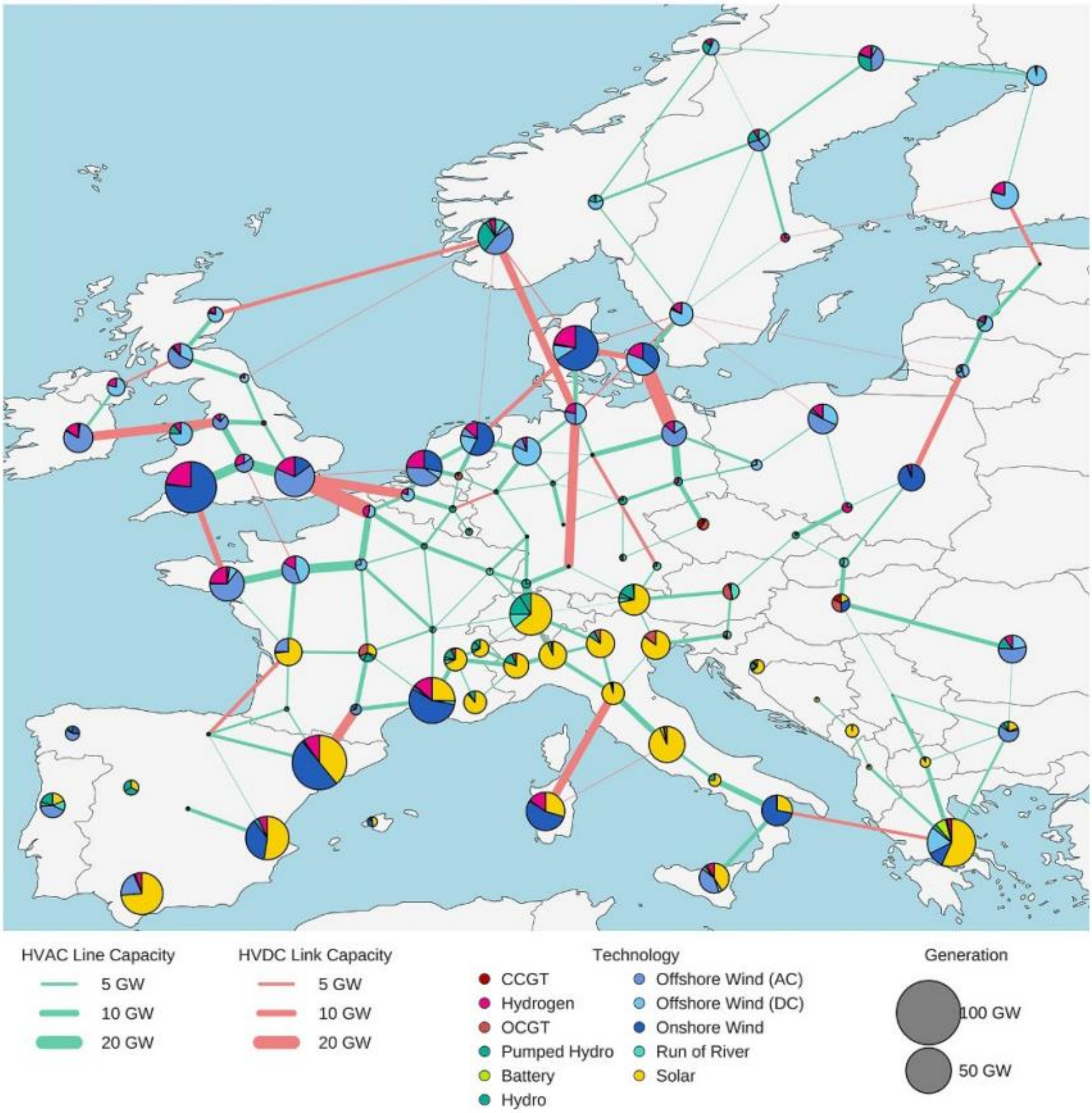

Figure 8: map of transmission line expansion, storage capacities, and power plant capacities per node in the optimal transmission network expansion with a 100% CO_2 reduction scenario in Neumann and Brown (2021).

6.4. The Effect of transmission network expansion on offshore wind capacity in the Netherlands (scenarios 1-3)

The effects of transmission expansion on the modeling outcomes are investigated in this section. In scenario 1, the transmission system cannot be expanded. The transmission system can be expanded by a maximum of 50% in scenario 2. In scenario 3, there is no domestic electricity requirement, and the transmission system can be expanded by a maximum of 150%. Table 24 presents the modeling results of scenarios 1, 2, and 3.

First of all, the total electricity generation and electricity use for energy storage in the North Sea countries increase in scenario 1. The annual system costs of the North Sea countries are also higher in scenario 1 compared with the baseline scenario. In scenario 2, it can be observed that a large part of the cost reduction by expanding the transmission system can be reached by a transmission system expansion of 50%. In contrast, when the domestic production requirement is lifted in scenario 3, electricity generation and the transmission system expansion decrease compared with the baseline scenario. In addition, annual system costs in the North Sea countries are lower in scenario 3 than in the baseline scenario.

The effects of transmission expansion on the modeling outcomes can be explained as follows: the electricity demand of the North Sea countries is 2711 TWh in scenarios 1, 2, and 3, which is higher than the electricity demand in 2013[52]. However, the size of the transmission system stays constant in scenario 1 and increases by 50% in scenario 2. Consequently, network congestion occurs more frequently in scenarios 1 and 2, which require more local electricity generation to match electricity demand. The lack of transmission capacity in scenarios 1 and 2 leads to less offshore wind power deployment and more solar deployment in the North Sea countries (see Table 36). Onshore wind power capacity remains constant in these scenarios due to the imposed onshore wind constraint. The opposite happens in scenario 3, where the transmission system expansion is higher than in the baseline scenario. As a result, total annual electricity system costs decrease in scenario 3 because renewable electricity can be generated at favorable locations, and the electricity can be exported to less favorable locations for renewable energy generation.

When transmission system expansion is constrained, electricity generation in the Netherlands increases significantly because the export of renewable electricity produced in Scandinavia to Germany is limited due to network congestion. In addition, more electricity is lost due to energy storage. Existing transmission capacity is then used to transport Dutch renewable electricity, which is largely produced by offshore wind turbines, from the Netherlands to Germany[53]. This effect is even stronger in scenario 2. When the domestic production constraint is lifted in scenario 3, an increase in Dutch electricity exports is observed compared with the baseline scenario. This can be explained by larger electricity exports from the Netherlands to Belgium and Germany. Belgian net electricity imports are 20 TWh in the baseline scenario and 27 TWh in scenario 3. Furthermore, German electricity imports are 201 TWh in the baseline scenario and 317 TWh in scenario 3 (see Table 37.

The demand for flexibility has also increased. Compared with the baseline scenario, more hydrogen storage is used in scenarios 1, 2, and 3. The increased hydrogen storage, fuel cell, and electrolyzer capacities in these scenarios correlate with electricity generation in the Netherlands. However, this effect is mitigated by the transmission system expansion. Scenario 1 has the highest hydrogen storage capacity, but scenario 2 has higher electricity generation in the Netherlands.

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[52] Electricity demand in the North Sea countries was 1869 TWh in 2013.

[53] It can be seen in Table 37 that Danish net exports decrease from 207 TWh in the baseline scenario to 25 TWh in scenario 1 and 128 TWh in scenario 2. German net exports are -201 TWh in the baseline scenario, -81 TWh in scenario 1, and -213 TWh in scenario 2.

Table 24: modeling results with varying transmission capacity constraints. Individual lines are allowed to be expanded by more than the capacity constraint, but the total transmission system expansion should be equal to or less than the set constraint.

	Unit	Baseline scenario: max 150% transmission system expansion	Scenario 1: no transmission system expansion	Scenario 2: max 50% transmission system expansion	Scenario 3: no domestic production constraint and max 150% transmission system expansion
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2711	2711	2711
Electricity generation	TWh	2953	3079	2988	2890
Electricity usage for energy storage	TWh	242	368	278	179
Transmission capacity expansion relative to existing grid	%	98	0	50	81
Total annual system costs North Sea countries	B. EUR/ year	130.4	143.5	132.4	128.6
Electricity costs per MWh	EUR/MWh	48.1	52.3	48.8	47.4
Import dependency as percentage of total electricity generation	%	0	0	0	0
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	195	195
Electricity generation	TWh	219	303	383	245
Net electricity export	TWh	7	60	144	97
HVAC expansion	%	186	0	148	126
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.0	56.4	76.0	54.9
Capacity offshore wind-ac	GW	15.7	10.5	10.5	10.5
Capacity offshore wind-dc	GW	26.3	45.9	65.6	44.4
Capacity solar PV	GW	10.2	16.3	10.2	10.2
Capacity nuclear power plants	GW	0	0	0	0
Production onshore wind	TWh	30.9	30.9	30.9	30.9
Production offshore wind	TWh	178.4	256.5	343.8	244.5
Production solar PV	TWh	9.7	15.5	9.7	9.7
Production nuclear power plants	TWh	0	0	0	0
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.0	12.7	11.5	5.8
Electrolysis capacity	GW	10.1	25.2	24.2	15.5
Fuel cell capacity	GW	31.6	51.7	69.6	39.2
Electricity consumption hydrolysis	TWh	31.1	87.9	81.7	46.8
Electricity generation fuel cells	TWh	14.5	40.8	37.9	21.7
Battery storage capacity	MWh	1.1	1.4	1.3	2.1
Battery charge capacity	MW	0.3	0.4	0.4	0.6
Battery discharge capacity	MW	0.4	0.4	0.4	0.7
Electricity consumption batteries	GWh	0.8	1.0	0.8	1.4
Electricity generation batteries	GWh	0.6	0.8	0.7	1.1

6.5. Effect of Dutch electricity demand on offshore wind capacity in the Netherlands (scenarios 4-6)

The effect of higher electricity demand in the Netherlands on the modeling outcomes is examined In this section. The electricity demand in the rest of the North Sea countries remains the same as in the baseline scenario. In scenario 4, Dutch electricity demand increases to 243 TWh. Electricity demand in the Netherlands increases to 386 TWh and 544 TWh in scenarios 5 and 6, respectively. The modeling outcomes are shown in Table 25.

First, an increase in electricity generation, electricity usage for energy storage, and transmission system expansion is observed when Dutch electricity demand increases in scenarios 4, 5, and 6. The costs of electricity per MWh also increase from 48.1 EUR/MWh in the baseline scenario to 48.9 EUR/MWh in scenario 4, 50.1 EUR/MWh in scenario 5, and 51.3 EUR/MWh in scenario 6. The higher annual system costs in the North Sea countries in scenarios 4, 5, and 6 can be explained by the higher costs of the transmission system expansion. Furthermore, more renewable energy needs to be deployed to match the higher electricity demand of the Netherlands. The costs of solar power and offshore wind deployment also increase because wind and solar capacities are deployed at less favorable locations to match the higher electricity demand in the Netherlands.

Electricity generation in the Netherlands and electricity exports increase in scenario 4, which means that the extra electricity demand in the Netherlands is produced domestically[54]. In scenario 4, electricity production increases by 65 TWh, of which 41 TWh (63%) is used to cover the increased electricity demand in the Netherlands, 18 TWh (28%) is used for electricity exports, and 6 TWh (9%) is lost due to more energy storage.

When the electricity demand in the Netherlands increases to 386 TWh, the extra electricity demand is partially covered by more electricity imports[55]. Electricity demand in the Netherlands increases with 191 TWh in scenario 5. This is covered by 108 TWh (57%) of domestic electricity production and 83 TWh (43%) more electricity imports. As a result, the Netherlands becomes a net electricity importer instead of an electricity exporter in scenario 5.

In addition, this effect becomes stronger when electricity demand in the Netherlands increases to 544 TWh in scenario 6. Electricity demand increases with 349 TWh, and electricity consumption for storage increases with 8 Twh in scenario 6 relative to the baseline scenario. This is covered by 217 TWh (61%) of domestic electricity production and 140 TWh (39%) more electricity imports. The onshore wind production in the Netherlands also increases in scenarios 5 and 6, but this does not lead to a lower electricity cost price.

Furthermore, energy storage, electrolyzer, and fuel cell capacities increase when the Dutch electricity demand increases because the demand for energy storage increases when electricity generation in the Netherlands increases. However, there is a drop in seasonal storage capacities in scenario 5 compared to scenario 4. Here, electricity imports provide flexibility to the system because the HVAC lines expansion shows the highest relative increase in scenario 5 compared with the baseline scenario.

[54] This is remarkable because it is expected that the Netherlands will import more electricity by increasing electricity demand, which can be observed in scenarios 5 and 6. In scenario 4, the Netherlands exports more electricity to Belgium than in the baseline scenario (see Table 37).

[55] The domestic production constraint limits the amount of electricity the Netherlands can import.

Table 25: modeling results of the fourth, fifth and sixth scenarios. In these scenarios, the yearly Dutch electricity demand is increased. The electricity demand in bordering countries of the Netherlands remains constant.

	Unit	Baseline scenario: Dutch electricity demand of 195 TWh	Scenario 4: Dutch electricity demand of 243 TWh	Scenario 5: Dutch electricity demand is 386 TWh	Scenario 6: Dutch electricity demand is 544 TWh
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2752	2901	3059
Electricity generation	TWh	2953	3006	3177	3363
Electricity usage for energy storage	TWh	242	254	275	304
Transmission capacity expansion relative to existing grid	%	98	102	116	125
Total annual system costs North Sea countries	B. EUR/ year	130.4	134.6	145.4	157.1
Electricity costs per MWh	EUR/MWh	48.1	48.9	50.1	51.3
Import dependency as percentage of total electricity generation	%	0	0	0	0
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	236	386	544
Electricity generation	TWh	219	284	327	436
Net electricity export	TWh	7	25	-76	-133
HVAC expansion	%	186	204	261	254
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.0	56.5	64.2	82.3
Capacity offshore wind-ac	GW	15.7	10.5	10.5	10.5
Capacity offshore wind-dc	GW	26.3	46.1	53.7	71.8
Capacity solar PV	GW	10.2	10.2	10.2	30.2
Capacity nuclear power plants	GW	0	0	0	0
Production onshore wind	TWh	30.9	31.0	32.4	33.0
Production offshore wind	TWh	178.4	243.0	285.2	374.0
Production solar PV	TWh	9.7	9.7	9.7	29.1
Production nuclear power plants	TWh	0	0	0	0
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.0	5.6	4.2	6.8
Electrolysis capacity	GW	10.1	13.6	10.0	12.9
Fuel cell capacity	GW	31.6	45.6	50.5	78.5
Electricity consumption hydrolysis	TWh	31.1	42.9	32.4	47.3
Electricity generation fuel cells	TWh	14.5	19.9	15.0	21.9
Battery storage capacity	MWh	1.1	1.9	3.1	4.6
Battery charge capacity	MW	0.3	0.6	0.9	1.4
Battery discharge capacity	MW	0.4	0.6	1.0	1.5
Electricity consumption batteries	GWh	0.8	1.3	2.1	3.0
Electricity generation batteries	GWh	0.6	1.1	1.7	2.4

6.6. Effect of nuclear power plants on offshore wind capacity in the Netherlands (scenarios 7-9)

In the following three scenarios, the effect of new nuclear power plants on offshore wind deployment in the energy system of the North Sea countries is investigated. In scenario 7, the Netherlands has a combined nuclear capacity of 3.5 GW. In scenario 8, the Netherlands has a nuclear power capacity of 3.5 GW, France has a 27 GW nuclear power plant capacity, and the UK has a 24 GW nuclear power plant capacity. The existing nuclear power fleet will be newly built in scenario 9 such that the nuclear power plant capacity in 2040 in the North Sea countries is the same as in 2020 (see Table 17). The modeling outcomes of scenarios 7, 8, and 9 are shown in Table 26.

First, electricity usage for storage and transmission system expansion will decrease if new nuclear power plants are built in the Netherlands. Moreover, the total annual system costs of the North Sea countries decrease when nuclear power plants are being built in the Netherlands. These effects are also observed when more nuclear power plants are incorporated into the electricity system of the North Sea countries in scenarios 8 and 9. This can be explained by the flexibility that nuclear power plants provide to the system, which has been observed empirically (Cany et al., 2018). However, the flexibility of nuclear power plants is overestimated in PyPSA-Eur because ramp rates and minimum power outputs are ignored. The high flexibility of nuclear power plants in PyPSA has also been recognized in the literature (Parzen et al., 2022, p.9). The electricity generation of nuclear power plants is illustrated in Figure 23 of appendix E.

In addition, offshore wind capacity deployment in the North Sea countries decreases sharply when nuclear power plants are built (see Table 32). This implies that nuclear power plants compete with offshore wind turbines. The energy import dependency of the North Sea countries also increases in these scenarios because uranium has to be imported from outside the North Sea countries (World Nuclear Association, 2022).

Furthermore, electricity generation from nuclear power plants in the Netherlands is 27 TWh in scenario 7. Subsequently, electricity generated by offshore wind turbines in the Netherlands decreases by 16 TWh compared with the baseline scenario. Electricity exports increase by 13 TWh, and 2 TWh less electricity is lost due to energy storage. Hence, 52% of the electricity generated by the nuclear power plants in the Netherlands is consumed domestically, and 48% is exported to neighboring countries.

In scenario 8, electricity generation from nuclear power plants is also 27 TWh, but electricity generation from offshore wind decreases by 68 TWh. This is because net electricity exports decrease by 28 TWh[56], and 12 TWh less electricity is lost due to energy storage. Moreover, in scenario 9, nuclear power plants in the Netherlands produce 4 TWh. However, electricity generation from offshore wind decreases by 67 TWh, mainly because the net electricity exports decrease by 50 TWh compared with the baseline scenario. Further, 13 TWh less electricity is lost due to energy storage. As a result, the optimal hydrogen storage capacity in the Netherlands decreases when nuclear power plants are integrated into the electricity system of the North Sea countries.

[56] This can be explained by the fact that France's net exports increase with 133 TWh in scenario 8 (see Table 37).

Table 26: modeling results with the incorporation of nuclear power plants in the system. In the seventh scenario, the Netherlands will have 3.500 GW of nuclear power plant capacity in Borsele. In scenario 8, the UK will have 24 GW, and France will have 27 GW of new nuclear power plant capacity. In the ninth scenario, the North Sea countries have the same nuclear power plant capacity as in 2020.

	Unit	Baseline scenario: no nuclear power plants in the system	Scenario 7: nuclear power plants in NL	Scenario 8: nuclear power plants in NL, France and the UK	Scenario 9: historic power plants in North Sea countries
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2711	2711	2711
Electricity generation	TWh	2953	2948	2887	2837
Electricity usage for energy storage	TWh	242	237	176	127
Transmission capacity expansion relative to existing grid	%	98	97	70	50
Total annual system costs North Sea countries	B. EUR/ year	130.4	130.2	128.7	127.6
Electricity costs per MWh	EUR/MWh	48.1	48.0	47.5	47.1
Import dependency as percentage of total electricity generation	%	0	0.9	14.92	27.74
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	178	195
Electricity generation	TWh	219	230	190	156
Net electricity export	TWh	7	20	-21	-43
HVAC expansion	%	186	182	106	83
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.0	37.3	27.0	25.1
Capacity offshore wind-ac	GW	15.7	15.7	15.7	15.7
Capacity offshore wind-dc	GW	26.3	21.6	9.5	9.4
Capacity solar PV	GW	10.2	10.2	10.2	10.2
Capacity nuclear power plants	GW	0	3.5	3.5	0.5
Production onshore wind	TWh	30.9	30.9	30.9	30.9
Production offshore wind	TWh	178.4	162.2	110.9	111,4
Production solar PV	TWh	9.7	9.7	9.7	9.7
Production nuclear power plants	TWh	0	27.0	26.8	4.2
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.0	3.7	2.2	2.1
Electrolysis capacity	GW	10.1	9.0	2.5	1.8
Fuel cell capacity	GW	31.6	28.6	18.9	27.9
Electricity consumption hydrolysis	TWh	31.1	27.6	8.4	7.0
Electricity generation fuel cells	TWh	14.5	12.8	3.9	3.2
Battery storage capacity	MWh	1.1	1.2	1.0	1.0
Battery charge capacity	MW	0.3	0.4	0.3	0.8
Battery discharge capacity	MW	0.4	0.4	0.3	0.6
Electricity consumption batteries	GWh	0.8	0.9	0.7	0.6
Electricity generation batteries	GWh	0.6	0.7	0.6	0.5

6.7. Effect of solar power capacity on offshore wind capacity in the Netherlands (scenarios 10-12)

The cost-optimized configuration of the baseline scenario includes only 10.2 GW of solar power capacity in the Netherlands. However, the Netherlands already surpassed 11 GW of solar power capacity in 2020 (PBL, 2021 In this section, the effect of more solar power capacity in the Netherlands on the modeling outcomes is researched. The solar power capacity in the rest of the North Sea countries is calculated by co-optimizing generation, network, and storage capacities. The solar power capacity in the Netherlands in scenarios 10, 11, and 12 is 30, 60, and 120 GW, respectively. The results are shown in Table 27.

First, it can be seen that the total electricity generation and usage for storage in the North Sea countries remain constant when the Netherlands installs more solar power capacity. The transmission capacity expansion in scenarios 10, 11, and 12 does not change much compared to the baseline scenario. The annual system costs increase when more solar power is deployed in the Netherlands, but the effect is less than 1% when 120 GW of solar capacity is installed. This can be explained as follows: the annual system costs are for all the North Sea countries, even though only the solar power capacities in the Netherlands are set in scenarios 10, 11, and 12. The total solar power capacity in the North Sea countries is 351 GW in the baseline scenario, 352 GW in scenario 10, 355 GW in scenario 11, and 361 GW in scenario 12 (see Table 36). This means that the increase in solar power capacity in the Netherlands is counteracted by reducing solar power deployment in other North Sea countries. Nevertheless, it has been found in the literature that decarbonized energy systems with much more solar power are possible with a limited cost increase (Neumann & Brown, 2021, p.5).

Second, electricity generation in the Netherlands increases when more solar PV is deployed. Part of the generated solar power is exported to bordering countries of the Netherlands, and a part of the electricity is used for energy storage. Further, the HVAC line capacities increase in the Netherlands in scenarios 10, 11, and 12.

In scenario 10, electricity generation by solar PV in the Netherlands increases by 19 TWh. As a result, electricity generation by offshore wind decreases by 7 TWh, net electricity exports of the Netherlands increase by 11 TWh, and 1 TWh more electricity is lost due to energy storage. Hence, 42% of the electricity generated by the extra solar power capacity in the Netherlands is consumed domestically, and 58% is exported to neighboring countries.

Electricity generation by solar PV in the Netherlands increases by 48 TWh in scenario 11. Subsequently, electricity generation by offshore wind decreases by 5 TWh, net electricity exports of the Netherlands increase by 34 TWh, and 9 TWh more electricity is lost due to energy storage. Therefore, 29% of the extra electricity generated by solar PV is consumed domestically, and 71% is exported to bordering countries of the Netherlands.

Furthermore, electricity generation by solar PV in the Netherlands increases by 104 TWh in scenario 12. The electricity generation by offshore wind in the Netherlands decreases by 27 TWh in scenario 12. Net electricity exports increase by 48 TWh, and 29 TWh more electricity is lost due to energy storage. As a result, 54% of the extra electricity generated by solar PV is consumed domestically, and 46% is exported to neighboring countries of the Netherlands.

Lastly, the demand for hydrogen storage increases when more solar power capacity is deployed in the Netherlands because more energy storage is required to smooth the effects of fluctuating solar generation. The capacities for hydrogen storage, fuel cells, and electrolyzers almost double when 120 GW solar power capacity is deployed, even though electricity generation increases by 35% relative to the baseline scenario in the Netherlands in scenario 12. The curtailment of solar energy in the North Sea countries remains at 0.2% low in scenarios 10, 11, and 12 (see Table 35). Hence, most of the excess solar energy is stored in seasonal hydrogen storage. More flexibility in the electric power system of the Netherlands is required when the share of solar power in electricity generation becomes larger.

Table 27: modeling results with varying solar PV capacities in the Netherlands. In the tenth, eleventh and twelfth scenario, there will be 30, 60 and 120 GW solar PV capacity in the Netherlands respectively.

	Unit	Baseline scenario: no set solar PV capacity in NL	Scenario 10: solar PV capacity in NL is 30 GW	Scenario 11: solar PV capacity in NL is 60 GW	Scenario 12: solar PV capacity in NL is 120 GW
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2711	2711	2711
Electricity generation	TWh	2953	2953	2953	2953
Electricity usage for energy storage	TWh	242	242	242	250
Transmission capacity expansion relative to existing grid	%	98	97	97	99
Total annual system costs North Sea countries	B. EUR/ year	130.4	130.5	130.7	131.3
Electricity costs per MWh	EUR/MWh	48.1	48.1	48.2	48.4
Import dependency as percentage of total electricity generation	%	0	0	0	0
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	195	195
Electricity generation	TWh	219	231	262	296
Net electricity export	TWh	7	18	41	55
HVAC expansion	%	186	183	191	249
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.0	40.1	39.0	35.2
Capacity offshore wind-ac	GW	15.7	15.7	15.7	15.7
Capacity offshore wind-dc	GW	26.3	24.4	23.3	19.5
Capacity solar PV	GW	10.2	30.0	60.0	120.0
Capacity nuclear power plants	GW	0	0	0	0
Production onshore wind	TWh	30.9	30.9	30.9	30.8
Production offshore wind	TWh	178.4	171.5	173.9	150.8
Production solar PV	TWh	9.7	28.6	57.3	114.1
Production nuclear power plants	TWh	0	0	0	0
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.0	4.2	5.8	10.1
Electrolysis capacity	GW	10.1	10.8	16.7	29.8
Fuel cell capacity	GW	31.6	32.3	43.0	66.7
Electricity consumption hydrolysis	TWh	31.1	33.1	49.1	85.4
Electricity generation fuel cells	TWh	14.5	15.3	22.8	39.6
Battery storage capacity	MWh	1.1	1.1	1.2	1.4
Battery charge capacity	MW	0.3	0.3	0.4	0.4
Battery discharge capacity	MW	0.4	0.3	0.4	0.4
Electricity consumption batteries	GWh	0.8	0.8	0.8	0.9
Electricity generation batteries	GWh	0.6	0.6	0.7	0.8

6.8. Effect of different cost assumptions and Dutch onshore wind constraint on offshore wind capacity in the Netherlands (scenarios 13-15)

The effect of alternating constraints and assumptions on the modeling outcomes is investigated in the following scenarios. In the thirteenth scenario, tank storage is used for hydrogen storage instead of salt caverns. In the fourteenth scenario, the onshore wind constraint in the Netherlands is relaxed to 20 GW. In the fifteenth scenario, the investment costs per kW for offshore wind turbines are decreased by 33.6%, such that the investment costs of onshore and offshore wind are equal.

First of all, the electricity generation and export decrease in scenario 13. When tank storage is used instead of salt caverns for seasonal hydrogen storage, the annual system costs and transmission system expansion are substantially higher. Hence, part of the flexibility that was provided by hydrogen storage is provided by transmission system expansion in scenario 13. However, the total offshore wind capacity in the North Sea countries increases in scenario 13 (see Table 36). Instead of storing the produced hydrogen, 14% of the electricity generation by offshore wind power is curtailed[57], compared to 3 to 4% curtailment of offshore wind energy in the baseline scenario (see Table 35). This would not happen in reality because green hydrogen is also in demand outside the electricity sector. Further, it can be seen that the hydrogen storage capacity is lower in scenario 13 due to the higher costs of tank storage compared with salt caverns. Moreover, in the Netherlands, offshore wind capacity decreases in scenario 13, and the Netherlands becomes a net electricity importer. Hence, expense tank storage leads to substantially less offshore wind deployment and energy use for seasonal storage.

When the Netherlands' onshore wind power capacity constraint is relaxed to 20 GW, the Dutch electricity generation and exports to neighboring countries increase. Electricity generation by onshore wind increases by 47 TWh in scenario 14. As a result, electricity generation by offshore wind decreases by 34 TWh, net electricity exports of the Netherlands increase by 9 TWh, and 3 TWh more electricity is lost due to energy storage. Hence, 81% of the electricity generated by the extra onshore wind capacity in the Netherlands is consumed domestically, and 19% is exported to neighboring countries. Furthermore, the annual system costs of the North Sea countries decrease. This is what can be expected because onshore wind power capacity is, with the made technology cost assumptions, cheaper than offshore wind capacity (see Table 38). Lastly, more hydrogen storage is required when the share of onshore wind power increases.

Additionally, a reduction of the investment costs of offshore wind turbines by 33.6% leads to lower annual system costs for the North Sea countries. Further, the total transmission system expansion decreases, and the electricity generation in the North Sea countries increases when the investment costs of offshore wind turbines are lower. In addition, Dutch electricity exports and the offshore wind capacity in the Netherlands increase in scenario 15. Onshore wind and solar power capacities remain constant in scenario 15. When looking at the aggregated generation capacities of the North Sea countries, it can be seen that offshore wind power substitutes onshore wind power and solar power capacities. Offshore wi+-nd power increases by 61 GW compared with the baseline scenario, whereas onshore wind power and solar power capacity decrease by 25 GW and 112 GW, respectively, compared with the baseline scenario. The hydrogen storage also increases, which is in line with the electricity generation in the Netherlands.

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[57] Curtailment is between 9% and 11% in the literature when steel tank storage is used in the PyPSA-Eur model (Schlachtberger et al., 2017, p.7).

Table 28: modeling results of scenarios thirteen, fourteen, and fifteen. Tank storage is used instead of salt caverns in the thirteenth scenario to store hydrogen. The onshore wind power constraint is raised to 20 GW in the fourteenth scenario. In the fifteenth scenario, the capital costs of offshore wind are 25% lower.

	Unit	Baseline scenario	Scenario 13: Tank storage for H_2 instead of salt caverns	Scenario 14: Dutch onshore wind power capacity constraint is set at 20 GW	Scenario 15: 33.6% lower offshore wind power capital costs
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2711	2711	2711
Electricity generation	TWh	2953	2938	2955	2967
Electricity usage for energy storage	TWh	242	227	244	256
Transmission capacity expansion relative to existing grid	%	98	150	99	94
Total annual system costs North Sea countries	B. EUR/ year	130.4	158.8	129.6	109.7
Electricity costs per MWh	EUR/MWh	48.1	58.6	47.8	40.5
Import dependency as percentage of total electricity generation	%	0	0	0	0
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	195	195
Electricity generation	TWh	219	156	232	247
Net electricity export	TWh	7	-42	16	32
HVAC expansion	%	186	245	199	203
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	20.0	8.0
Capacity offshore wind	GW	42.0	25.8	34.3	47.5
Capacity offshore wind-ac	GW	15.7	15.7	15.7	15.7
Capacity offshore wind-dc	GW	26.3	10.1	18.5	31.8
Capacity solar PV	GW	10.2	10.2	10.2	10.2
Capacity nuclear power plants	GW	0	0	0	0
Production onshore wind	TWh	30.9	29.9	77.8	30.9
Production offshore wind	TWh	178.4	116.6	144.1	206.2
Production solar PV	TWh	9.7	9.7	9.7	9.7
Production nuclear power plants	TWh	0	0	0	0
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.0	0.3	4.7	4.5
Electrolysis capacity	GW	10.1	1.4	12.3	10.6
Fuel cell capacity	GW	31.6	11.2	32.8	42.2
Electricity consumption hydrolysis	TWh	31.1	5.1	37.3	36.7
Electricity generation fuel cells	TWh	14.5	2.4	17.3	17.0
Battery storage capacity	MWh	1.1	1.4	0.9	0.6
Battery charge capacity	MW	0.3	0.4	0.3	0.2
Battery discharge capacity	MW	0.4	0.5	0.3	0.2
Electricity consumption batteries	GWh	0.8	1.6	0.7	0.6
Electricity generation batteries	GWh	0.6	1.3	0.6	0.5

6.9. Effect of hydrogen import for power generation on offshore wind capacity in the Netherlands (scenarios 16-18)

Hydrogen is used for seasonal energy storage in the baseline scenario, and green hydrogen is produced when there is more renewable electricity generation than electricity demand. However, green hydrogen can also be imported from abroad. In scenarios 16, 17, and 18, hydrogen can be imported from outside the North Sea countries at scenario-specific import prices. In scenario 16, an unlimited amount of hydrogen can be imported that can be used for electricity generation for an import price of 60 EUR/MWh. In the seventeenth scenario, an unlimited amount of hydrogen can be imported that can be used for electricity generation for an import price of 45 EUR/MWh. In the eighteenth scenario, the availability of hydrogen that can be imported is limited to 270 TWh[58], and the hydrogen import price is 45 EUR/MWh.

First, electricity generation in the North Sea countries decreases when green hydrogen can be imported. Imported hydrogen substitutes domestic hydrogen used for seasonal energy storage, which lowers the electricity usage for storage in the North Sea countries. Electricity use for energy storage decreases from 242 TWh in the baseline scenario to 146 TWh in scenario 16. In scenario 17, electricity use decreases to 21 TWh. When hydrogen can be imported for 60 Eur/TWh, 49% of the hydrogen for seasonal storage is produced in the North Sea countries. If hydrogen can be imported for 45 Eur/TWh, only 4% of the hydrogen for seasonal storage is produced in the North Sea countries. When hydrogen import can be imported for 45 Eur/TWh, but the supply is limited to 270 TWh, 42% of the hydrogen for seasonal storage is produced in the North Sea countries[59].

Furthermore, the transmission system expansion decreases in scenarios 16, 17, and 18 because hydrogen combustion is dispatchable, and this reduces the need for electricity trade in the cost-optimal solutions. The annual system costs of the electricity system of the North Sea countries also decrease since the imported hydrogen is cheaper than domestically produced hydrogen storage, and less infrastructure investment is made in the cost-optimized solution. The import dependency of the North Sea countries increases in these scenarios because hydrogen can be imported from outside the North Sea countries.

Moreover, the Netherlands' electricity generation and exports have increased in scenarios 16 and 18. On the other hand, electricity generation decreases in scenario 17 due to lower electricity exports from the Netherlands and less electricity usage for energy storage. As a result, offshore wind capacity in the Netherlands increases in scenarios 16 and 18, and decreases in scenario 17. Furthermore, onshore wind and solar power capacities remain constant in the Netherlands, and fuel cell capacities for imported hydrogen are 10.3 GW, 14.5 GW, and 5.1 GW for scenarios 16, 17, and 18, respectively.

Lastly, the demand for hydrogen storage decreases when imported hydrogen is used for electricity generation. In scenario 16 and scenario 18, the dispatchable generation is provided by a combination of imported hydrogen and domestically produced seasonal hydrogen storage. The seasonal storage in scenario 17 is completely substituted by imported hydrogen, and the domestic hydrogen storage capacity is only 0.3 GWh in scenario 17.

[58] The higher heating value (HHV) of hydrogen is used.

[59] Electricity generation from imported hydrogen is 126.4 TWh in scenario 16, 511,8 TWh in scenario 17, and 157.3 TWh in scenario 18. Domestic hydrogen production is calculated using the round-trip efficiency of seasonal hydrogen storage since the electricity usage for energy storage is known.

Table 29: modeling results of the 16th, 17th, and 18th scenarios. In scenario 16, green hydrogen can be imported from outside the North Sea countries for 60 EUR/MWh. In scenario 17, hydrogen can be imported for 45 EUR/ MWh. In scenario 18, green hydrogen can be imported for 45 EUR/MWh with a maximum of 270 TWh.

	Unit	Baseline scenario: no green H_2 import allowed	Scenario 16: green H_2 import for 60 EUR/MWh	Scenario 17: green H_2 import for 45 EUR/MWh	Scenario 18: green H_2 import for 45 EUR/MWh, with supply constraint
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2711	2711	2711
Electricity generation	TWh	2953	2857	2731	2844
Electricity usage for energy storage	TWh	242	146	21	133
Transmission capacity expansion relative to existing grid	%	98	94	45	90
Total annual system costs North Sea countries	B. EUR/ year	130.4	127.1	119.4	123.1
Electricity costs per MWh	EUR/MWh	48.1	46.9	44.3	45.2
Import dependency as percentage of total electricity generation	%	0	4.6	18.21	5.8
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	195	195
Electricity generation	TWh	219	226	214	221
Net electricity export	TWh	7	19	19	15
HVAC expansion	%	186	209	121	202
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.0	44.3	38.7	43.4
Capacity offshore wind-ac	GW	15.7	15.7	15.7	15.7
Capacity offshore wind-dc	GW	26.3	28.6	23.0	27.7
Capacity solar PV	GW	10.2	10.2	10.2	10.2
Capacity nuclear power plants	GW	0	0	0	0
Capacity fuel cells imported H_2	GW	0	10.3	14.5	5.1
Production onshore wind	TWh	30.9	30.9	30.9	30.9
Production offshore wind	TWh	178.4	182.8	162.2	180.6
Production solar PV	TWh	9.7	9.7	9.7	9.7
Production nuclear power plants	TWh	0	0	0	0
Production fuel cells imported H_2	TWh	0	3.0	11.7	0.2
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.0	1.9	0	1.7
Electrolysis capacity	GW	10.1	8.8	0	8.0
Fuel cell capacity	GW	31.6	8.5	0	6.9
Electricity consumption hydrolysis	TWh	31.1	22.9	0	20.2
Electricity generation fuel cells	TWh	14.5	10.6	0	9.4
Battery storage capacity	MWh	1.1	0.7	0.6	0.6
Battery charge capacity	MW	0.3	0.2	0.2	0.2
Battery discharge capacity	MW	0.4	0.2	0.2	0.2
Electricity consumption batteries	GWh	0.8	0.5	0.4	0.5
Electricity generation batteries	GWh	0.6	0.4	0.3	0.4

6.10. Effect of electricity demand of neighboring countries on offshore wind capacity in the Netherlands (scenarios 19-21)

It was found in scenarios 4, 5, and 6 that higher electricity demand in the Netherlands led to more domestic electricity generation. However, this effect was lowered due to more electricity imports from neighboring countries. In this section, the effect of higher electricity demand in bordering countries of the Netherlands on the modeling outcomes is investigated. Electricity demand in neighboring countries is 10% higher in scenario 19, 25% higher in scenario 20, and 50% higher in scenario 21. The electricity demand in the Netherlands in scenarios 19, 20, and 21 remains the same as in the baseline scenario. The electric load of each country in scenarios 19, 20, and 21 is shown in Table 18.

First of all, the electricity generation, electricity usage for energy storage, and transmission network expansion in the North Sea countries increase when the total electrical load of the system increase. The electricity generation in the North Sea countries increases in order to match electricity supply with demand. The need for flexibility increases because peak load increases when the electric load of the system is linearly scaled in the bordering countries of the Netherlands.

Further, it can be observed that the total annual system costs of the North Sea countries increase when the electricity demand of the system increases. This is because extra offshore wind and solar capacity need to be deployed in order to match the increased electricity demand. Offshore wind capacity increases from 338 GW in the baseline scenario to 581 GW in scenario 21, and solar capacity increases from 351 GW in the baseline scenario to 719 GW in scenario 21. In addition, onshore wind and hydroelectric power capacities remain constant, and these generation technologies will take a smaller share in the electricity mix when electricity demand increases (see Table 36). Furthermore, the larger transmission system expansion contributes to the annualized system costs because it is assumed that existing network components are fully amortized, but this does not apply to infrastructure expansion.

Moreover, electricity exports of the Netherlands increase when electricity demand in neighboring countries increases. All this extra electricity export is generated by more offshore wind capacity since onshore wind, and solar power capacities in the Netherlands remain constant. It can also be seen that electricity exports of the Netherlands increase non-linearly in the optimization. The highest rise in Dutch electricity exports occurs when electricity demand in neighboring countries increases by 10 percent. When the electricity demand of neighboring countries increases by 25 and 50 percent, the increase in Dutch electricity exports becomes smaller.

Finally, the hydrogen storage capacity increases when the electricity demand in neighboring countries increases and more than triples compared with the baseline scenario in scenario 21. This increase is in line with the extra electricity generation in scenarios 19, 20, and 21.

Table 30: modeling results of scenarios 19, 20, and 21. In these scenarios, the electricity demand of the North Sea countries is increased by 10%, 25%, and 50%, respectively, while holding the electricity demand of the Netherlands and Luxembourg constant.

	Unit	Baseline scenario	Scenario 19: 10% higher electricity demand in neighboring countries	Scenario 20: 25% higher electricity demand in neighboring countries	Scenario 21: 50% higher electricity demand in neighboring countries
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2961	3336	3962
Electricity generation	TWh	2953	3246	3676	4401
Electricity usage for energy storage	TWh	242	285	339	439
Transmission capacity expansion relative to existing grid	%	98	110	130	150
Total annual system costs North Sea countries	B. EUR/ year	130.4	150.6	179.5	229.9
Electricity costs per MWh	EUR/MWh	48.1	50.9	53.8	58.0
Import dependency as percentage of total electricity generation	%	0	0	0	0
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	195	195
Electricity generation	TWh	219	318	366	450
Net electricity export	TWh	7	92	131	204
HVAC expansion	%	186	279	340	351
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.0	61.0	72.0	91.3
Capacity offshore wind-ac	GW	15.7	10.5	10.5	10.5
Capacity offshore wind-dc	GW	26.3	50.5	61.6	80.8
Capacity solar PV	GW	10.2	10.2	10.2	10.2
Capacity nuclear power plants	GW	0	0	0	0
Production onshore wind	TWh	30.9	30.9	30.9	30.9
Production offshore wind	TWh	178.4	277.0	325.9	409.3
Production solar PV	TWh	9.7	9.7	9.7	9.7
Production nuclear power plants	TWh	0	0	0	0
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.0	6.9	9.7	12.2
Electrolysis capacity	GW	10.1	18.2	23.6	28.5
Fuel cell capacity	GW	31.6	42.6	55.7	57.9
Electricity consumption hydrolysis	TWh	31.1	55.7	75.4	95.3
Electricity generation fuel cells	TWh	14.5	25.8	35.0	44.2
Battery storage capacity	MWh	1.1	1.4	1.4	2.1
Battery charge capacity	MW	0.3	0.4	0.4	0.6
Battery discharge capacity	MW	0.4	0.5	0.4	0.9
Electricity consumption batteries	GWh	0.8	1.0	0.9	1.3
Electricity generation batteries	GWh	0.6	0.8	0.8	1.1

6.11. Effect of different renewable energy constraints in neighboring countries on offshore wind capacity in the Netherlands (scenarios 22-24)

This section investigates the effect of more onshore wind power capacity, solar power capacity, and offshore wind capacity in the North Sea countries on the modeling outcomes. In scenario 22, the onshore wind power constraint is relaxed, and two times as much onshore wind power capacity is allowed in bordering countries of the Netherlands. Scenario 23 examines the effect of at least 50% more solar power capacity compared with the baseline scenario in the bordering countries of the Netherlands. Scenario 24 incorporates more offshore wind power in the neighboring countries of the Netherlands based on national targets. The minimum and maximum capacity constraints of generation technologies are shown in Table 19.

When more onshore wind capacity is deployed in the system, electricity generation and electricity usage for energy storage in the North Sea countries decrease. An increase in transmission capacity expansion can explain the decreases in electricity use for energy storage, and wind energy curtailment is higher in scenario 22 (see Table 35). Furthermore, the annual system costs decreased in scenario 22 compared with the baseline scenario. Onshore wind increases from 270 GW in the baseline scenario to 527 GW in scenario 22, and offshore wind capacity decreases from 338 GW in the baseline scenario to 144 GW in scenario 22. Hence, offshore wind capacity is substituted by onshore wind capacity in scenario 22. (see Table 36). The lower annual system costs of the North Sea countries are because onshore wind substitutes offshore wind, and onshore wind is cheaper with the cost assumptions made in this research.

Moreover, an increase in solar power capacity deployment in neighboring countries in scenario 23 lead to slightly more electricity generation and electricity usage for energy storage in the North Sea countries. The transmission system expansion in the North Sea countries increases in scenario 23, as well as the annual system costs of the North Sea countries. In scenario 23, offshore wind capacity increases from 338 GW in the baseline scenario to 316 GW in scenario 23, and solar power capacity increases from 351 GW to 534 GW in scenario 23. This implies that more solar power and less offshore wind capacity in the North Sea countries do not lead to a much more expensive energy system.

Additionally, more offshore capacity in neighboring countries of the Netherlands in scenario 24 leads to slightly less electricity generation and energy usage for storage in the North Sea countries. In addition, transmission system expansion and the annual system costs are higher in scenario 24. The total onshore wind power capacity in the North Sea countries is also lower than the set constraint of 270 GW in scenario 24. This means that offshore wind power has substituted onshore wind capacity in scenario 24 but at a higher cost. Compared to the baseline scenario, the total annual system costs increase in scenario 24 because offshore wind is more expensive than onshore wind with the cost assumptions made in this research.

In addition, higher renewable energy capacities in neighboring countries influence the capacities in the Netherlands in cost-optimized solutions. In scenario 22, Dutch electricity generation decreases, offshore wind capacity decreases in the Netherlands, and the Netherlands becomes an electricity importer. In contrast, Dutch electricity exports and offshore wind capacity in the Netherlands increase in scenario 23. In addition, Dutch electricity generation and offshore wind capacity decrease when more offshore wind capacity is installed in neighboring countries in scenario 24. Solar power capacity in the Netherlands also increases substantially in scenario 24. Lastly, battery storage capacity increases substantially in scenario 24 compared to the baseline scenario.

Table 31: modeling results of scenarios 22, 23, and 24. In scenario 22, onshore wind power capacity constraints are two times higher in neighboring countries. In scenario 23, the solar capacity is 50% higher than in the baseline scenario. Neighboring countries have large capacities of offshore wind power in scenario 24.

	Unit	Baseline scenario	Scenario 22: doubled onshore wind power capacity constraint	Scenario 23: more solar in neighboring countries	Scenario 24: more offshore wind in neighboring countries
General statistics electric power system of the North Sea countries					
Electrical load	TWh	2711	2711	2711	2711
Electricity generation	TWh	2953	2895	2960	2952
Electricity usage for energy storage	TWh	242	184	249	241
Transmission capacity expansion relative to existing grid	%	98	108	101	106
Total annual system costs North Sea countries	B. EUR/ year	130.4	120.1	132.0	134.9
Electricity costs per MWh	EUR/MWh	48.1	44.3	48.7	49.8
Import dependency as percentage of total electricity generation	%	0	0	0	0
Transmission system statistics of the Netherlands					
Electrical load	TWh	195	195	195	195
Electricity generation	TWh	219	156	222	156
Net electricity export	TWh	7	-46	14	-51
HVAC expansion	%	186	226	160	295
HVDC expansion	%	0	0	0	0
Power generation statistics of the Netherlands					
Capacity onshore wind	GW	8.0	8.0	8.0	8.0
Capacity offshore wind	GW	42.0	25.3	42.8	18.3
Capacity offshore wind-ac	GW	15.7	10.5	15.7	15.7
Capacity offshore wind-dc	GW	26.3	14.8	27.1	2.6
Capacity solar PV	GW	10.2	12.0	10.2	48.0
Capacity nuclear power plants	GW	0	0	0	0
Production onshore wind	TWh	30.9	30.9	30.9	30.9
Production offshore wind	TWh	178.4	113.9	181.9	79.5
Production solar PV	TWh	9.7	11.4	9.7	45.8
Production nuclear power plants	TWh	0	0	0	0
Power system flexibility statistics of the Netherlands					
Hydrogen storage capacity	TWh	4.0	1.6	5.0	2.7
Electrolysis capacity	GW	10.1	3.8	7.3	6.5
Fuel cell capacity	GW	31.6	22.7	28.4	29.6
Electricity consumption hydrolysis	TWh	31.1	12.2	23.7	21.6
Electricity generation fuel cells	TWh	14.5	5.7	11.0	10.0
Battery storage capacity	MWh	1.1	1.0	6.7	12.4
Battery charge capacity	MW	0.3	0.3	2.0	3.7
Battery discharge capacity	MW	0.4	0.3	2.2	4.1
Electricity consumption batteries	GWh	0.8	0.7	4.7	8.8
Electricity generation batteries	GWh	0.6	0.5	3.8	7.2

6.12. Conclusions energy system effects on offshore wind power deployment in the Netherlands

In this section, the conclusions of the modeling scenarios on offshore wind deployment in the Netherlands are presented. These scenarios aim to explore the energy system effects on offshore wind power deployment in the Netherlands. The offshore wind capacities in the Netherlands in each scenario are shown in Figure 9.

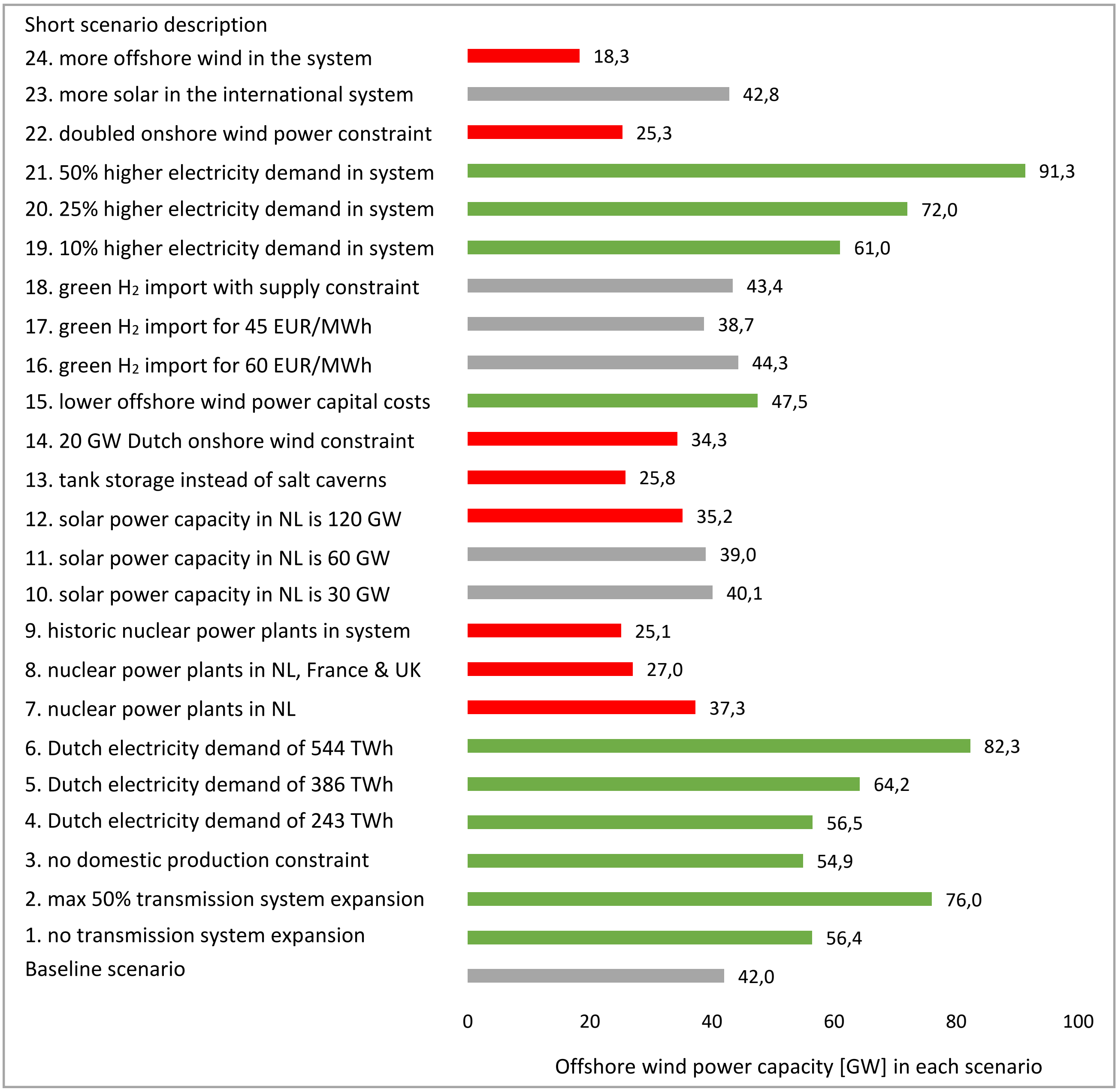

Figure 9: overview of offshore wind power capacities in each scenario. An increase in offshore wind capacity of more than 10% relative to the baseline scenario is coloured in green, a decrease of more than 10% is coloured red and a change of less than 10% relative to the baseline scenario is coloured in grey. A comprehensive description of the scenarios is shown in Table 16.

Effect of transmission system expansion on offshore wind capacity (scenarios 1-3)

The maximum transmission expansion in the baseline scenario is limited to 150%. When transmission expansion is not allowed or constrained, electricity exports of the Netherlands to neighboring countries increase. Moreover, electricity usage for energy storage and the annual system cost increase when the network expansion is limited. If the transmission system expansion is limited to 50%, a large part of the cost reduction by transmission expansion can already be reached. Electricity exports and offshore wind capacity also increase when the domestic production constraint is lifted. Hence, constraining transmission expansion or limiting electricity exports by imposing a domestic production constraint leads to more offshore wind capacity deployment in the Netherlands in the cost-optimal solution.

Effect of varying electricity demand on offshore wind capacity (scenarios 4-6, 19-21)
The results show that more offshore wind capacity is deployed in the Netherlands when the electricity demand of the Netherlands increases, holding everything else constant. In general, part of the extra demand is covered by domestic electricity generation, and part of the electricity is imported from abroad. However, the optimization results did not show a linear relationship between the change in electricity demand and domestic electricity export. In addition, an increase in electricity demand in neighboring countries of the Netherlands leads to more Dutch electricity exports. As a result, offshore wind capacity in the Netherlands rises. However, a non-linear relationship was found between Dutch electricity exports and electricity demand in neighboring countries of the Netherlands.

Effect of competing low-carbon energy technologies on offshore wind capacity (scenarios 7-12, 14, 22-24)
Installing more onshore wind, solar PV, or nuclear power in the Netherlands leads to less offshore wind capacity in the Netherlands in the optimization. The extent to which offshore wind capacity is substituted by the competing low-carbon energy technology depends on the change in electricity exports and the electricity usage for energy storage. However, the ratio of domestic electricity use and extra electricity exports varies when more renewable capacity is deployed.

When nuclear power plants are built in the Netherlands, about half of the electricity generated by nuclear power plants is consumed domestically, and about half generated electricity is exported. Electricity exports decrease sharply when nuclear power plants are also built in neighboring countries such as France and the UK. As a result, the Netherlands becomes a net electricity importer, and offshore wind capacity decreases in the Netherlands in the cost-optimal solution.

In addition, the modeling results show that offshore wind capacity decrease when more solar capacity is installed in the Netherlands. The results show that, on average, roughly 60 percent of the extra generated solar energy is exported. In addition, more energy storage is required when the share of electricity production from solar increases. Additionally, the annual system costs do not increase much when more solar power capacity is incorporated into the system, which suggests that technologically diverse solutions exist for a slight cost increase.

Moreover, the results show that a relaxation of the onshore wind constraint in the Netherlands leads to less offshore wind power deployment in the Netherlands. However, in contrast to solar power, more than 80 percent of the electricity generated by onshore wind turbines is consumed domestically instead of exported. More onshore wind deployment in the Netherlands also leads to a reduction of the annual system costs.

The effect of more renewable energy in neighboring countries is also investigated. It has been shown that the Netherlands imports more electricity when neighbouring countries install more onshore and offshore wind capacity. Furthermore, the modeling results show that more solar power capacity in neighboring countries leads to slightly more offshore wind capacity in the Netherlands while increasing net electricity exports of the Netherlands.

Effect of green hydrogen imports on offshore wind capacity (scenarios 16-18)

The effect of green hydrogen imports on power generation is also examined. The modeling results show that hydrogen combustion for power generation decreases electricity generation in the North Sea countries. This is because the electricity consumption for seasonal hydrogen storage decreases when green hydrogen can be imported from abroad. The offshore wind capacity in the Netherlands decreases slightly when abundant cheap hydrogen can be imported because less electricity is needed for domestic hydrogen storage. Electricity exports of the Netherlands slightly increase when green hydrogen can be imported for 60 euros per MWh, or when a supply constraint is imposed of 270 MWh. As a result, offshore wind capacity in the Netherlands increases. Furthermore, about half of the hydrogen is imported when hydrogen can be imported for 60 euros per MWh. If hydrogen can be imported for 45 euros per MWh, almost all consumed hydrogen for electricity generation is imported.

7. Discussion

This section discusses the results of the research. Section 7.1 compares the estimated offshore wind capacity in the North Sea countries in this thesis with offshore wind capacity estimations of previous modeling studies. After that, section 7.2 compares the hydrogen storage and battery capacities in the modeling results for the Netherlands to the Dutch battery and hydrogen storage capacities in the literature. Lastly, section 7.3 discusses the outcomes of the modeling, the used assumptions, and the uncertainties of the model.

7.1. Comparison results to other power system modeling studies

In this section, the results of the modeling are compared to three other modeling studies that investigated the offshore wind capacity in the North Sea countries. The offshore wind capacities in each study are shown in Table 32.

Table 32: offshore wind capacity [GW] in the North Sea countries in different studies.

Country	Baseline scenario	Müller et al. (2017)	Martínez-Gordón et al. (2022)	Global Ambition scenario 2040 TYNDP 2022
Belgium [GW]	19,4	22	1,8	5,9
Denmark [GW]	56,6	3	2,3	24,9
France [GW]	60,5	45	0	44,9
Germany [GW]	32,5	74	27,9	59,9
Ireland [GW]	2,7	2	0	5,9
Luxembourg [GW]	0	2	0	0
Netherlands [GW]	42	33	47,4	50
Norway [GW]	3,9	0	4,7	3,4
Sweden [GW]	8,6	0	0	4,5
United Kingdom [GW]	111,7	54	103,6	59,9
Total offshore wind capacity [GW]	337,9	235	187,7	267,5
Electricity demand [TWh]	2953	2136	4220	2810

Müller et al. (2017) estimated the amount of offshore wind capacity needed in the North Seas in 2045 to meet the Paris Climate Change Conference targets. Based on a 50% energy demand reduction and an electrification rate of 45%, a 230 GW offshore wind capacity for 2045 is estimated, of which 33 GW will be deployed in the Dutch part of the North Sea. The offshore wind capacity in Müller et al. (2017) is lower than the offshore wind capacity in the baseline scenario of this study. This difference can be explained by the total electricity generation of the North Sea countries, which is 2136 TWh in Müller et al. (2017) and 2953 TWh in the baseline scenario. There is also a difference in the estimated amount of wind turbines in Germany, which is considerably higher in Müller et al. (2017) than in the baseline scenario. Germany imports much electricity from Denmark in the baseline scenario (see Table 37), whereas Germany is more self-sufficient in Müller et al. (2017)[60].

Martínez-Gordón et al. (2022) estimated lower offshore wind capacities in the North Sea countries than the baseline scenario. Electricity generation in the North Sea counties is higher in Martínez-Gordón et al.

[60] Germany's offshore wind capacity is 59 GW in the study of Müller et al. (2017), and Germany's offshore wind capacity is 33 GW in the baseline scenario of this research.

(2022) than in the baseline scenario. However, onshore wind and solar PV account for most electricity generation. Offshore wind is mainly used for hydrogen production. Only Germany and the Netherlands reached their maximum technical potential for offshore wind.

Moreover, the Global Ambition scenario in the TYNDP 2022 has 26% less offshore wind capacity than the baseline scenario of this research. In contrast, electricity generation in the TYNDP 2022 is 8% higher than in the baseline scenario. Further, the Global Ambition scenario of the TYNDP 2022 deployed more solar PV and less onshore wind power than the baseline scenario of this research. However, nuclear power plants are used in the Global Ambition scenario of the TYNDP 2022, and nuclear power plants compete with offshore wind turbines. In addition, offshore wind capacity in Germany in the Global Ambition scenario of the TYNDP 2022 is higher than in the baseline scenario of this study. Fewer electricity imports from Denmark and more electricity generation from gas turbines in Germany can explain this. Lastly, Belgium imports more electricity in the Global Ambition scenario of the TYNDP 2022, and Belgium has less offshore wind capacity than in the baseline scenario of this research.

7.2. Comparison flexibility options baseline scenario to the II3050 and TNO 2022.

The flexibility options of the baseline scenario are discussed in this section. Hydrogen storage is used in this research for dispatchable electricity generation to balance electricity supply and demand. The electrolyzer and fuel cell capacities in the baseline scenario are 10.1 GW and 31.6 GW, respectively. Hydrogen is only dedicated to electricity generation in the baseline scenario. This is not the case in the II3050 and TNO 2022. The electrolyzer capacity in the II3050 ranges from 16.2 GW in the International Steering scenario to 50.6 GW in the National Steering scenario. The electrolyzer capacity in TNO 2022 is 20 GW in the ADAPT scenario and 67 GW in the TRANSFORM scenario (Scheepers et al., 2022, p.30). The total conventional generation capacity in the II3050 ranges from 32.8 GW to 36.2 GW (Netbeheer Nederland, 2021, p.133).

In addition, conventional electricity generation in TNO 2022 ranges from 4.2 GW in ADAPT to 8.5 GW in TRANSFORM (Scheepers et al., 2022, p.30). Hence, electrolyzer capacity in the baseline scenario is in the same order of magnitude as in the International Steering scenario when corrected for the higher electricity demand. The conventional generation capacity in the baseline scenario is in the same order of magnitude as the capacities in the II3050, and the conventional generation capacity in the baseline scenario is significantly higher than the capacities in TNO 2022.

Battery storage plays a minor role in the baseline scenario, and the capacity of the batteries for short-term electricity storage is 1.1 MWh. In the II3050, electricity storage ranges from 0.2 TWh to 0.4 TWh (Netbeheer Nederland, 2021, p.133). However, battery storage in the II3050 also entails home batteries and batteries in electric vehicles that can be used for demand response (Netbeheer Nederland, 2021, p.133). Battery storage is not quantified in TNO 2022.

The fuel cells and electrolyzer capacities at each node are illustrated in Figure 10. Large fuel cell and electrolyzer capacities exist in the UK, Denmark, Germany, France, the Netherlands, and Belgium. In general, the size of the storage capacities is positively correlated with the renewable power capacities in each node. There is little hydrogen storage in Norway, Sweden, Southwest of Germany, and east of France. This can be explained by the pumped-storage hydropower and hydroelectric power plants with storage capacities in these regions, which can provide flexibility to the electric power system.

The fuel cell capacities are also larger than the electrolyzer capacities in the North Sea countries. This means that slow charging and quick discharge at some moments in the system are desirable. It has also been observed in the literature that electrolyzer capacity is generally smaller than the fuel cell capacity (Parzen et al., 2022, p.13).

Lastly, the aggregated electricity generation per technology of the North Sea countries of the baseline scenario is illustrated in Appendix E. The aggregated state of charge and charging and discharging of energy storage facilities are displayed in Appendix F.

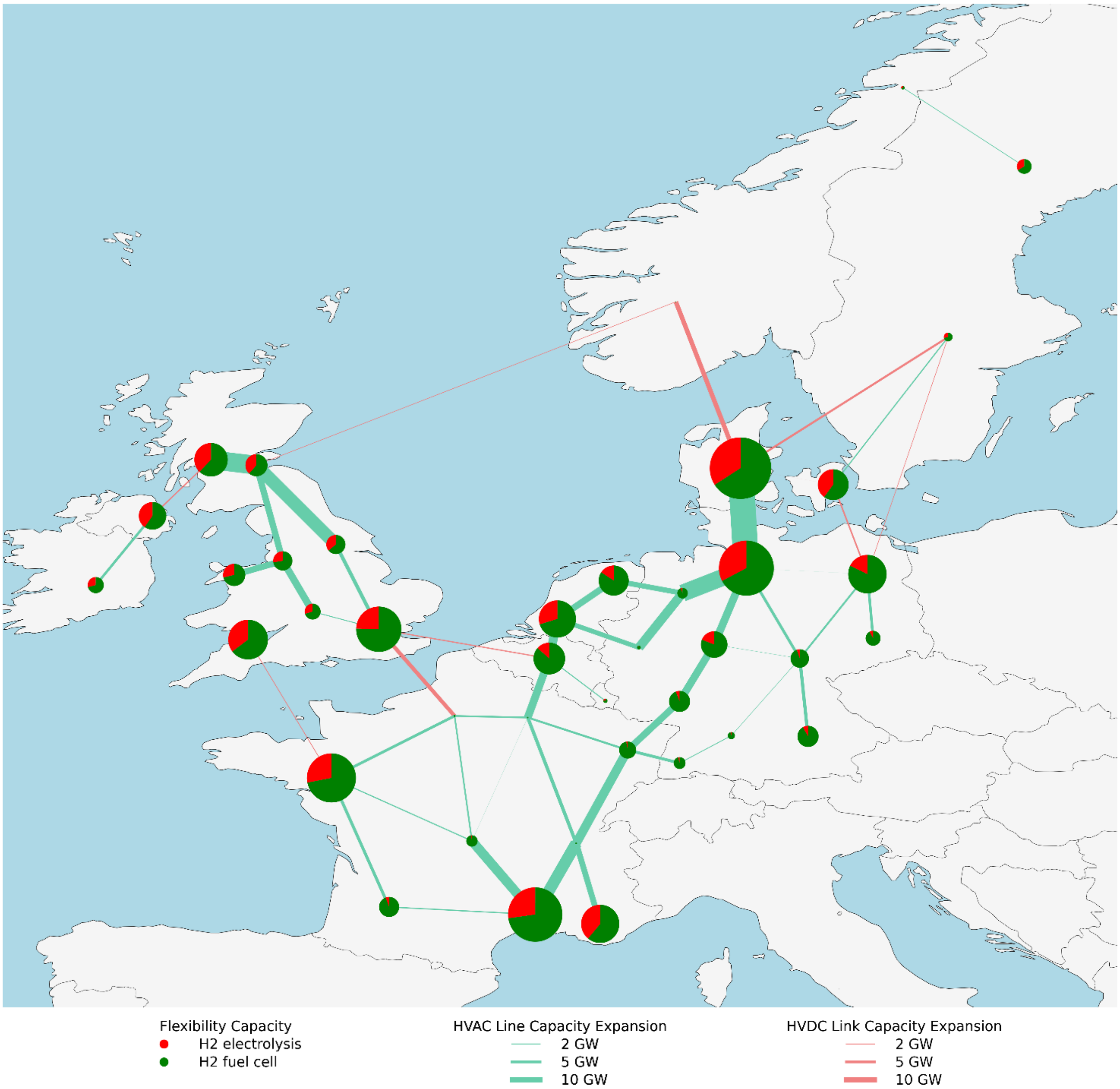

Figure 10: hydrogen electrolysis capacity, hydrogen fuel cell capacity, and the transmission network expansion of the baseline scenario.

7.3. Model discussions and uncertainties

The following paragraphs discuss the assumptions and uncertainties of the used model in this thesis. Thereby, improvements to the model are proposed.

7.3.1. The effect of the onshore wind constraint

This section discusses the effect of the onshore wind constraint. Table 33 compares the onshore wind constraints in different scenario studies. The maximum amount of onshore wind power in each country in this research is high compared to the REG scenario in Fit for 55 and the Global Ambition scenario in TYNDP 2022.

The largest relative difference in onshore wind capacity is in Denmark and Sweden, and the largest absolute difference in onshore wind capacity is in Germany. When the onshore wind constraints in Scandinavia are tightened, Germany will import less electricity from Scandinavia. Nevertheless, much electricity exports from Scandinavia to Germany has also been found in the literature (Martínez-Gordón et al., 2022, p.13). In addition, the Netherlands will export more electricity to Germany because Germany is not endowed with a high potential for offshore wind energy. As a result, more offshore wind capacity is deployed in the Netherlands.

Table 33: onshore wind power capacities in different studies.

Country	Onshore wind capacity constraint in this research [MW]	Onshore wind capacity in 2030 according to REG scenario of 'Fit for 55' [MW]	Onshore wind capacity in 2040 according to Global Ambition scenario[61] of 'TYNDP 2022' [MW]
Belgium	6600	6600	4825
Denmark	14500	9100	4926
France	50700	50700	37092
Germany	105000	80300	62160
Ireland	8200	7500	4300
Luxembourg	550	600	350
Netherlands	8000	21900	8423
Norway	11400	-	9004
Sweden	32000	10900	15683
United Kingdom	33000	-	27829

Furthermore, Belgium has less onshore wind capacity in the Global Ambition scenario of the TYNDP 2022 than in the REG scenario in Fit for 55. Subsequently, Belgium is expected to import more electricity from the Netherlands and France. This effect is moderated by the domestic production constraint of 80%, which limits the amount of electricity that each North Sea country can be imported. In conclusion, the onshore wind constraint in the baseline scenario is relatively high, which likely underestimates the Dutch demand for offshore wind capacity.

7.3.2. Effect of the weather year

Simulation results depend on the assumptions concerning the model's input data, parameters, and constraints. It has been observed that the total system costs of the PyPSA-Eur model are robust over multiple weather years. Further, the total system costs are weakly affected by different load samples and renewable generation time series. Nevertheless, specific technologies might be affected by inter-annual variability. Especially Dunkelfluate[62] events are a challenge for energy systems if a significant amount of electricity is generated by renewables. Therefore, the most robust results are found using weather data from several years (Schlachtberger et al., 2018, p.15).

7.3.3. Geographical scope of the system

The scope of the system in this study is limited to the North Sea countries to enhance the model's tractability. The electricity flows may shift when more countries are included in the system, such as Switzerland. In the baseline scenario, much electricity flows from Scandinavia to the south of Germany. Switzerland could provide

[61] The weather year 2008 is chosen

[62] A Dunkelflaute is a term used to describe a period with little to no energy that can be generated using wind and solar power.

flexibility to the electric power system because it has abundant hydropower resources. In addition, cheap solar energy from the South of Europe may reduce solar power capacities in Northern Europe and increase the amount of wind energy capacities in the North of Europe.

7.3.4. Battery storage

In most scenarios in this research, the battery storage capacity is around 1 MWh in the Netherlands. This is a low capacity considering that the storage operation limit of battery storage is 6 hours, which would be 133 GWh for the Netherlands[63]. The battery storage capacity in the Netherlands is 9.8 MWh in the baseline scenario with a 1-hourly resolution, which is still on the low side (see Table 21). This is remarkable because battery storage has a high round-trip efficiency of 81%, which is higher than the round-trip efficiency of pumped-hydro energy storage (75%) and the round-trip efficiency of hydrogen storage (46%). Battery storage is beneficial for short-term smoothing, and batteries allow more efficient usage of fluctuating solar generation. The assumed costs of battery storage relative to hydrogen storage can potentially explain the low amount of battery storage in the cost-optimal solutions. Battery storage has investment costs of 192 EUR/kWh, whereas hydrogen storage in salt caverns has investment costs of 0.84 EUR/kWh (see Table 39). Even though battery storage has a higher round-trip efficiency than hydrogen storage, hydrogen storage costs are less than 1% of battery storage's investment costs.

In addition, it has been shown in the literature that installed battery increases exponentially with decreasing costs (Schlachtberger et al., 2018, p.10). Neumann and Brown (2021), who used the PyPSA-Eur model in their study, also found a very low battery capacity in the cost-optimal solution. However, Neumann and Brown (2021) found that decarbonized energy systems are possible with 200 GW battery storage when the annual system costs of the North Sea countries are 5% higher. In their study, the electric load is 3138 TWh, and the investment cost of battery storage is 310 Eur/KWh. In contrast, the electric load in the baseline scenario of this study is 2711 TWh, and the investment cost of battery storage is 192 Eur/KWh. According to Neumann and Brown (2021), "Even for a complete decarbonization of the European power system building energy storage is not essential, although they are deployed in response to e.g. minimizing network reinforcement" (p.5).

7.3.5. Perfect foresight assumption

A greenfield optimization approach has been adopted in this thesis, except for the transmission grid and hydroelectric power plants. Furthermore, a perfect foresight method over one optimization year is used. This means that all information is known to the solver from the starting point, and no transition is assumed. In reality, decision-makers have reduced foresight. There could be large amounts of unutilized - and thus stranded – capacities if climate targets are taken seriously. For instance, the over-construction of fossil generation in the 2020s can occur due to short-sighted political and business strategies. This leads to higher system costs than the baseline scenario (Löffler et al., 2019).

7.3.6. Consideration of non-technical factors

Social-technical and political factors, such as a low acceptance of onshore wind power and transmission line investments, may affect the transition pathway scenarios based on techno-economic factors alone. Some options resonate better within society than others. Since a rapid transition to a low-carbon energy system is required, there is a need for technologies that are well-accepted in society (Bolwig et al., 2020). This thesis

[63] Annual electricity demand of the Netherlands in the baseline scenario is 195 TWh, which corresponds to 133 GWh for 6 hours.

considers reduced support for onshore wind by setting an onshore wind power constraint for each country. The transmission expansion is limited to 150% in the baseline scenario, but this constraint is not very restrictive. The total system costs will be higher if the transmission expansion constraint is tightened.

Since the Russian invasion of Ukraine, energy security has also become an essential consideration for policymakers. The North Sea countries are self-sufficient in the baseline scenario. The North sea countries have the highest import dependency in scenario 17 due to hydrogen imports for power generation[64]. However, wind turbines require rare-earth elements (mainly neodymium, praseodymium, and dysprosium), and these materials could become bottlenecks in deploying wind turbines in the future (Li et al., 2020).

[64] The energy import dependency is 18.21% in scenario 17.

8. Conclusions and outlook

This thesis explores the factors influencing the Dutch demand for offshore wind in the North Sea in 2040. Scenario analysis is conducted to research the drivers of electricity demand growth in the Netherlands. After that, power system modeling is used to explore the energy system effects of installing many offshore wind turbines in the North Sea. In section 8.1, the research sub-questions and the main research question are answered. Section 8.2 discusses the potential implication of the thesis' results for policymakers. Finally, suggestions for future research are provided in section 8.3.

8.1 Answering the main research question

RSQ 1: "Which factors influence the future electricity demand in the Netherlands, and what are estimates of future renewable power generation in the Netherlands in a decarbonized energy system?"

A scenario analysis is conducted to determine the factors that determine future electricity supply and demand in the Netherlands. The future estimated electricity demand of the Netherlands is divided into five categories: built environment excluding heating, heating in the built environment, agriculture, transportation, industry, and hydrogen production. The category hydrogen consists of green hydrogen and synthetic fuels, and the category industry includes only the direct energy use for heat production in the industry.

In conclusion, it was found that the most important factors that influence future electricity demand in the Netherlands are green hydrogen production and energy use for heat production in the industry. The spread in estimations are as follows: the category built environment has an estimated electricity demand of 59-67 TWh, the category heating in the built environment has an estimated electricity demand of 16-29 TWh, the category agriculture has an estimated electricity demand of 12-25 TWh, the category industry has an estimated electricity demand of 69-118 TWh and the category hydrogen has an estimated electricity demand of 0-292 TWh. If hydrogen is not included, then the spread in the expected electricity demand is relatively modest; an electricity demand of 177-270 TWh is expected in 2050 in the Netherlands without hydrogen.

On the supply side, wind and solar energy are expected to play a major role in a highly decarbonized Dutch energy system. Estimations for offshore wind are 28-72 GW, estimations for onshore wind are 6-20 GW, and estimations for solar PV are 36-125 GW. Nuclear power and other low-carbon energy technologies will play a minor role in power supply, and conventional generation using green hydrogen or biomethane is used to provide flexibility to the system.

The second sub-question focuses on the electricity system effects on offshore wind demand in the Netherlands.

RSQ 2: "What configurations of offshore wind capacity, electricity demand, import and export of electricity, solar power capacity, and hydrogen import in 2040 lead to the lowest societal costs for the North Sea countries while being compatible with the Paris Climate Agreement and maintaining high security of supply?"

Energy system effects have been investigated using power system modeling. The cheapest energy system has been found in scenario 17, where green hydrogen can be imported for 45 euros per MWh. The reduction of the annual system costs of North Sea countries is caused by a lower need for flexibility since the imported hydrogen is cheaper than domestically produced hydrogen storage, and hydrogen-fuelled power plants are dispatchable. The second cheapest energy system was found in scenario 22, where the onshore wind power constraints in neighboring countries of the Netherlands were relaxed. Hence, the system costs decrease when onshore wind capacity substitutes offshore wind capacity. Furthermore, there is relatively little solar power capacity in the baseline scenario. Increasing the amount of solar power capacity increases the system costs. However, the difference is modest, implying that systems with a higher share of solar energy are possible with a slight cost increase. Deploying more nuclear power plants in the system lowers the annual system costs. However, the cost reduction is mainly caused by the flexibility that nuclear power plants provide, so whether nuclear power plants decrease the system costs remains inconclusive.

The degree of self-sufficiency of the Netherlands depends on the Netherlands' net electricity export and whether fuels need to be imported from abroad. When new nuclear power plants are built, uranium needs to be imported from outside the North Sea countries, increasing the Netherlands' energy dependency. The Netherlands also becomes dependent on energy imports when imported hydrogen substitutes domestic hydrogen production.

Moreover, the modeling results show that the role of the Netherlands as either an importer or exporter of electricity depends strongly on the electricity demand in the Netherlands and neighboring countries. More offshore wind capacity is deployed in the Dutch part of the North Sea when electricity demand rises in neighboring countries, but this relation is non-linear. On the other hand, increasing electricity demand in the Netherlands can be partly covered by electricity imports. Furthermore, when renewable capacity is deployed in the Netherlands, the Netherlands exports more electricity. In contrast, the Netherlands imports more electricity when renewable capacity is deployed in neighboring countries. How much electricity is exported or consumed domestically depends on the installed renewable energy technology. Electricity generated by more onshore wind is mostly consumed domestically, and onshore wind substitutes offshore wind capacity. Additionally, about half of the electricity generated by new nuclear power plants is exported, and most electricity generated by more solar power capacity is exported.

Lastly, constraining the transmission system expansion increases annual system cost and the amount of offshore wind capacity in the Netherlands in the cost-optimal solution. In addition, lifting the minimal domestic production constraint, which requires each country to produce a certain percentage of its demand, increases the Dutch offshore wind capacity and lowers the annual system costs. Finally, the main research question can be answered.

"What is the Dutch demand for offshore wind capacity in the North Sea in 2040 in a decarbonized energy system, considering future electricity demand, electricity trade, and security of supply?"

The introduction mentioned that the estimations for offshore wind in the Netherlands range from 38 GW to 72 GW in 2050. Based on the scenario analysis, the lower bound of 38 GW offshore wind capacity can be reached without green hydrogen production. According to the scenario studies, the upper bound of 72 GW can only be reached when the Netherlands produces green hydrogen on a large scale. Therefore, policy choices need to be made about whether hydrogen will be produced domestically or imported abroad. In the latter case, the Netherlands is only partially self-sufficient.

From the modeling results, it was found that electricity demand in the Netherlands and bordering countries of the Netherlands are the most significant determinants for offshore wind capacity in the Netherlands, and an increase in electricity demand in either the Netherlands or its bordering countries is covered by a combination of extra domestic production and electricity import. It has also been found that the Netherlands is in a good position to export electricity to Germany and Belgium, especially when transmission expansion is limited. Hence, the Dutch demand for offshore wind demand becomes higher when the Netherlands aims to become an electricity exporter. Moreover it has been shown that onshore wind turbines and nuclear power plants compete with offshore wind turbines in cost-optimal solutions. This means that the

Dutch demand for offshore wind demand capacity becomes smaller when much onshore wind or nuclear power capacity is deployed in the Netherlands before 2040.

8.2. Policy insights and recommendations

Several recommendations for policymakers are given based on the results, conclusion, and discussion of this thesis. First, the Dutch government plans to investigate 50 GW offshore wind capacity in 2040 and 70 GW offshore wind capacity in 2050. From the scenario analysis, it has been shown that green hydrogen production is needed to have sufficient electricity demand for 50 GW offshore wind capacity. Hydrogen infrastructure is required to create sufficient electricity demand for 50 GW offshore wind in the Netherlands without considering electricity trade. Therefore, the first recommendation is to create a strategy for the development of hydrogen infrastructure in Northwestern Europe.

Second, the target of the Dutch government is to install 21 GW offshore wind capacity in the Dutch part of the North Sea by 2030. The results show that the offshore wind capacity in the Netherlands can be doubled to 42 GW in 2040. If much more offshore wind capacity is necessary depends on the domestic (green) hydrogen production in 2040. It has also been found that (green) hydrogen import for electricity generation is competitive with domestic hydrogen production for 60 Eur/TWh. At that price, about half of the hydrogen is imported, and about half is produced domestically.

Further, when hydrogen is excluded, electricity demand is expected to increase sharply in the coming decades, from 120 TWh in 2020 to 177-270 TWh in 2050. This increase is mostly driven by the adoption of electric vehicles in transportation, heat pumps in the built environment, and electrification in industry. Nevertheless, adequate adoption of these technologies is necessary to guarantee sufficient electricity demand for a good business case for offshore wind investments. Policymakers should consider electrification policies to guarantee sufficient electricity demand. This is needed to avoid the cannibalization of the business case for offshore wind energy, which is especially relevant when subsidies are allocated for offshore wind. Hence, the second recommendation for policymakers is to create electrification policies that are aligned with the national offshore wind targets. The analyzed scenario studies make assumptions about the adoption of new technologies, travel behavior, the size of the energy-intensive industry, the size of the agricultural sector, and the insulation level of residences. Therefore, the electrification policies should contain a clear vision because these energy policies can have consequences that go beyond the energy sector.

In addition, the results of the power system modeling show that future energy policies should have an international scope. An offshore wind park can supply electricity to multiple countries, and the modeling results show that international coordination benefits renewable energy policies. Belgium is endowed with few renewable energy resources, whereas Denmark has plenty of renewable energy resources that can be dedicated to export. Cross-border interconnection provides flexibility to the energy system and can lower total system costs. However, the role of the Netherlands as an electricity importer or exporter is indeterminate. Therefore, the third recommendation is that international cooperation should have a more important role in national energy policies.

Lastly, it has been shown that nuclear power plants compete with offshore wind turbines in cost-optimal solutions. In the modelling, part of the generated electricity was exported to bordering countries of the Netherlands. In November 2022, the Netherlands announced its plans to build two new nuclear power plants in Borsele (NOS Nieuws, 2022). Since Borsele is close to Belgium and power flows are not bound to national borders, the fourth recommendation is to include Belgian stakeholders in the construction plans.

8.3. Research outlook

Based on the results and limitations of this research, several directions for future research are discussed and substantiated in the following sections.

8.3.1. Sector coupling

Green hydrogen is a promising energy carrier for decarbonizing heating, transportation, and feedstock. Hydrogen is used in the model for backup power when renewable electricity supply is lower than the electricity demand. Consequently, hydrogen is also produced when the electricity price is high, which would not make economic sense. Other sectors, such as industry and transportation, also compete for (cheap) hydrogen, influencing the demand for offshore wind capacity. The PyPSA-Eur-sec model builds on the PyPSA-Eur model and completes the energy system. Therefore, this research could be extended by using a sector-coupled energy model.

8.3.2. Modeling for near-optimal solutions

The objective function in the used model used in this thesis minimizes the societal costs, which generates only a single optimal solution for each scenario. Providing a single solution underplays the degree of freedom in designing cost-effective future interventions in energy systems. Near-optimal alternatives may stand out due to other attractive properties, such as social acceptance. A common technique used to explore investment flexibility is MGA which uses the optimal solutions as an anchor point to explore the surrounding decision space for maximally different solutions. Therefore, MGA can be used to complement this research.

8.3.3. Emerging renewable energy technologies

The modeling is limited to solar and wind energy, hydroelectric power, nuclear power, and hydrogen combustion for power generation. Various technologies are not included, such as floating solar energy. It might be interesting in future research to investigate whether floating solar can complement offshore wind energy to increase the North Sea's renewable energy potential. Furthermore, the role of wave energy in the North Sea can be interesting for further research.

8.3.4. Myopic optimization

A green-field approach with perfect foresight was used to model a future energy system in the North Sea countries. The modeled future energy system relies mainly on solar and wind energy, with hydrogen power plants as a dispatchable source of electricity. In reality, decision-makers do not possess a crystal ball that can predict the future perfectly. Changing circumstances, future uncertainties, and high capital requirements of long-term energy projects can result in short-term measures and postponement of long-term strategic decisions. In myopic optimization models, decision-makers have the foresight of a number of years shorter than the full timeframe studied (Fuso Nerini et al., 2017). Hence, this research can be enhanced using myopic modeling techniques to model a future energy system.

A. Selection power system model

Table 34: overview of power system models.

Energy system model	Criterion 1: Accessibility	Criterion 2: spatial granularity	Criterion 3: sectoral coverage	Criterion 4: temporal granularity	Criterion 5: Optimization
Balmorel		X	X	X	X
Calliope	X	X	X	X	X
Dieter			X	X	X
EMMA		X	X	X	X
EnergyPlan	X		X	X	X
Ficus	X	X	X	X	X
HOMER		X	X	X	X
NEMO	X	X	X	X	X
OSeMOSYS	X	X	X	X	X
Pandapower	X		X		X
PyPSA	X	X	X	X	X
Renpass		X	X	X	X
RETScreen		X	X		X
stELMOD		X	X	X	X
SWITCH	X	X	X	X	X
TEMOA	X	X	X	X	X
TIMES		X	X	X	X
urbs	X	X	X	X	X

B. Electric load curve North Sea countries

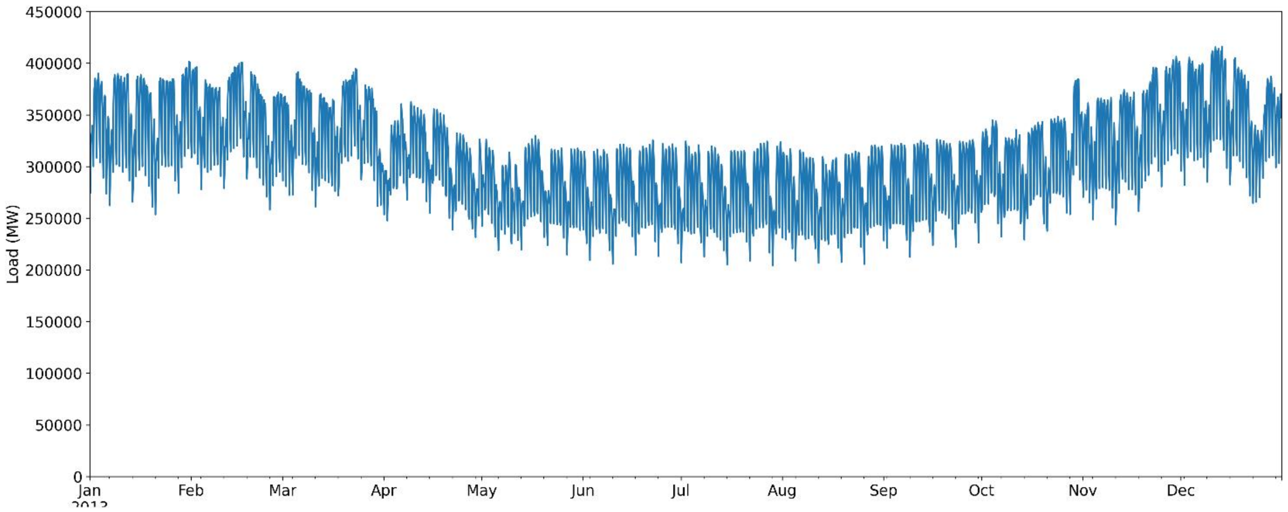

Figure 11: electric load of the Netherlands taken from the TYNDP Global Ambition scenario for 2040. The yearly load of the Netherlands is 195 TWh.

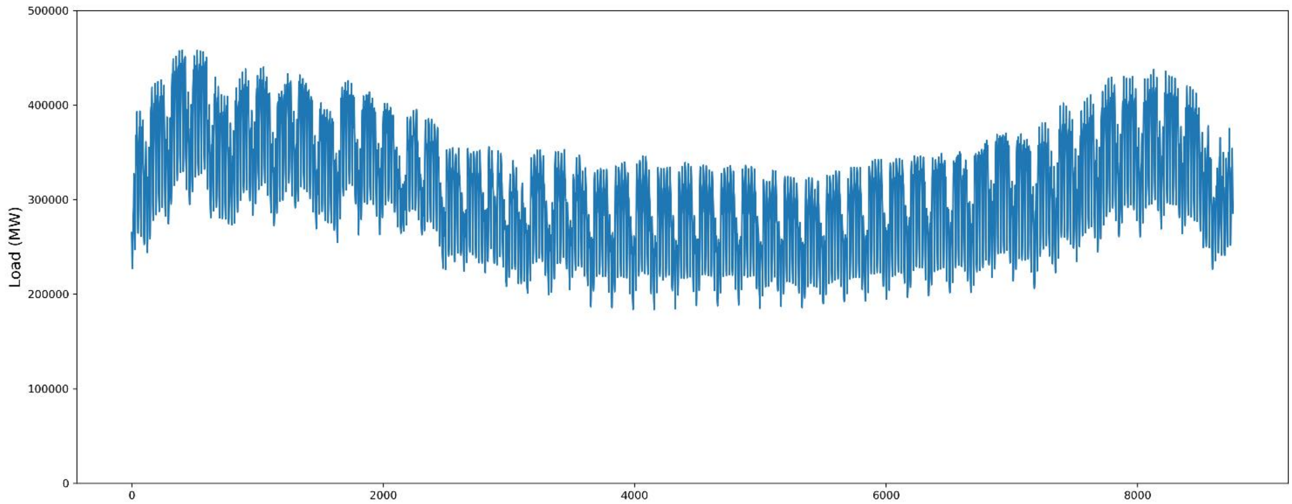

Figure 12: linearly scaled historic load of 2013 of the Netherlands. The yearly load of the Netherlands is 195 TWh.

C. Modeled electricity prices

Figure 13 shows the average marginal electricity price in the North sea countries and Figure 14 shows the price duration curve of the North Sea countries without the peak price. These marginal electricity prices are a long-term equilibrium given by the optimized capacity expansion model. This means that all generators have to recover their OPEX and CAPEX from the revenue, which is given by the production times the marginal price. This means that the costs of network expansion also needs to be recovered and this requires prices above the marginal costs of the most expensive generators. It is also higher than the average system costs because scarcity costs induced by the constraints are included Schlachtberger et al., 2017, p.477).

Furthermore, Figure 15 shows the locations marginal prices in the North Sea countries. It can be seen that the lowest electricity prices can be found in Great Britain and Scandinavia, whereas the highest electricity prices are in the South of Germany. Overall, the price differences between countries are modest, which means that there is a strong market integration in the baseline scenario.

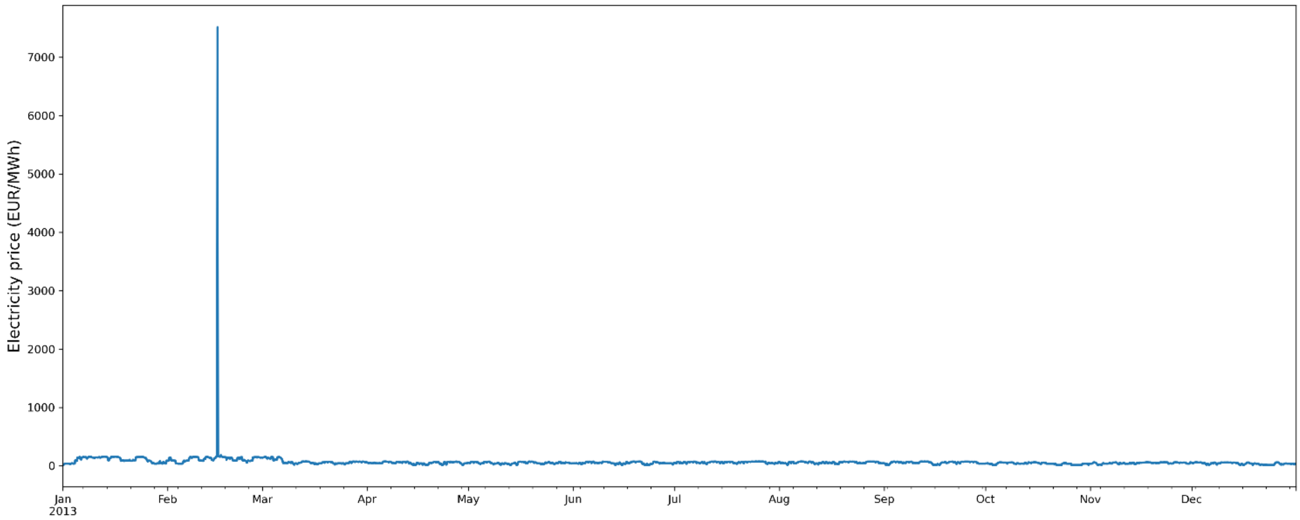

Figure 13: average marginal electricity price in the North Sea countries in the baseline scenario.

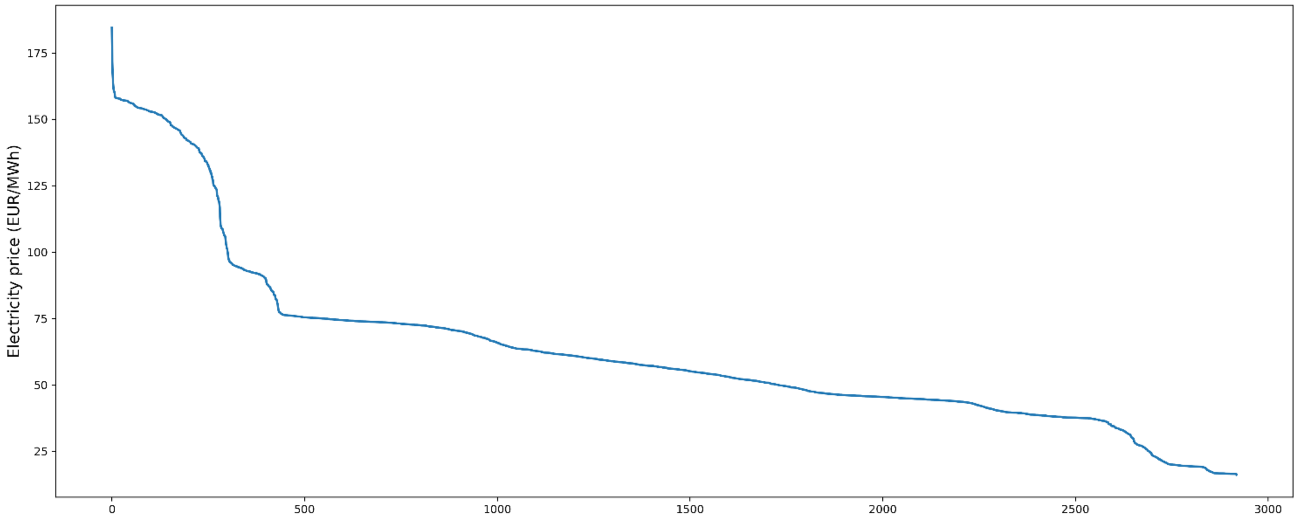

Figure 14: sorted average marginal electricity price of the North Sea countries in the baseline scenario without the peak price of 7512 EUR/MWh.

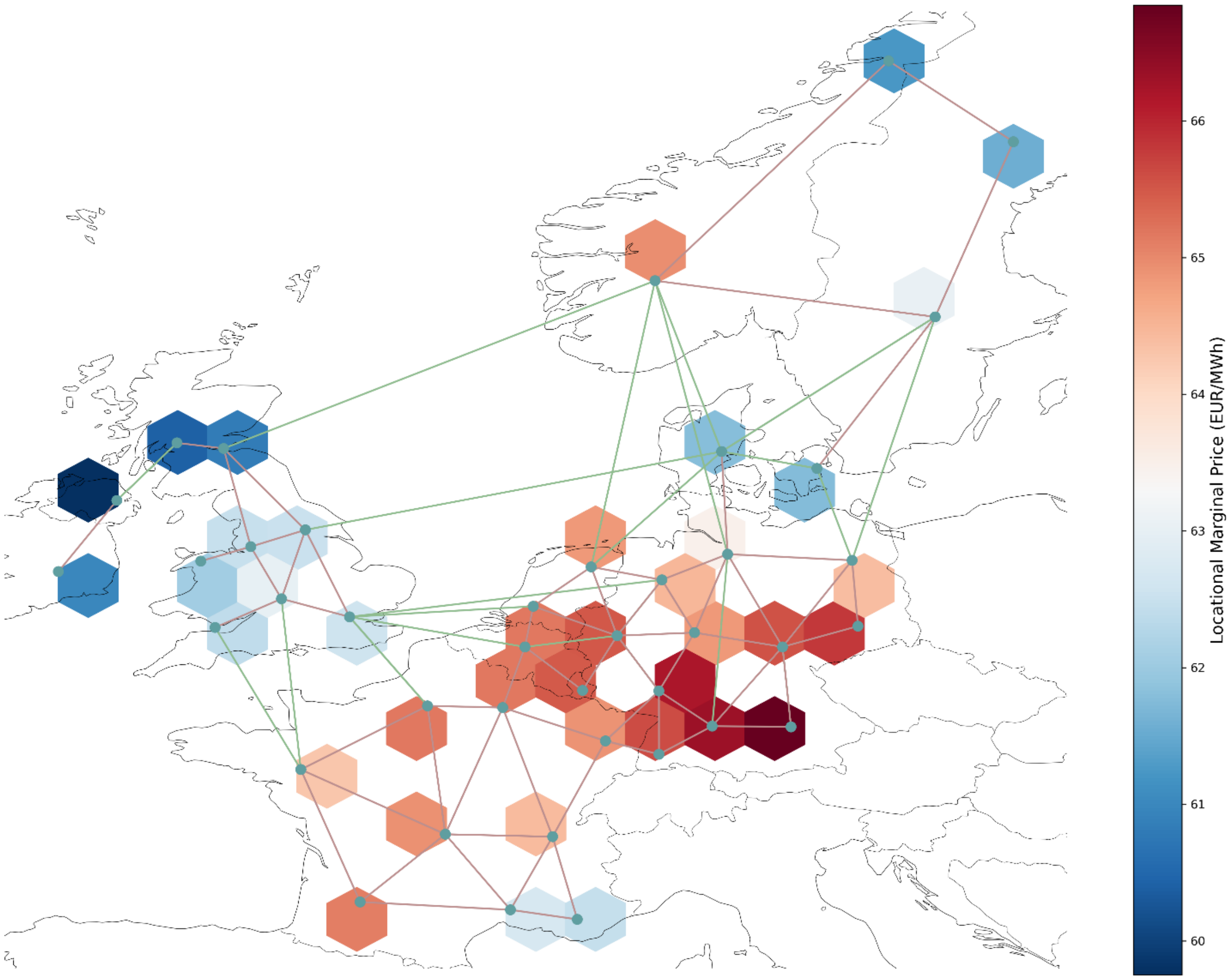

Figure 15: locational average electricity price in the North Sea countries [EUR/MWh].

D. Modeled Transmission system

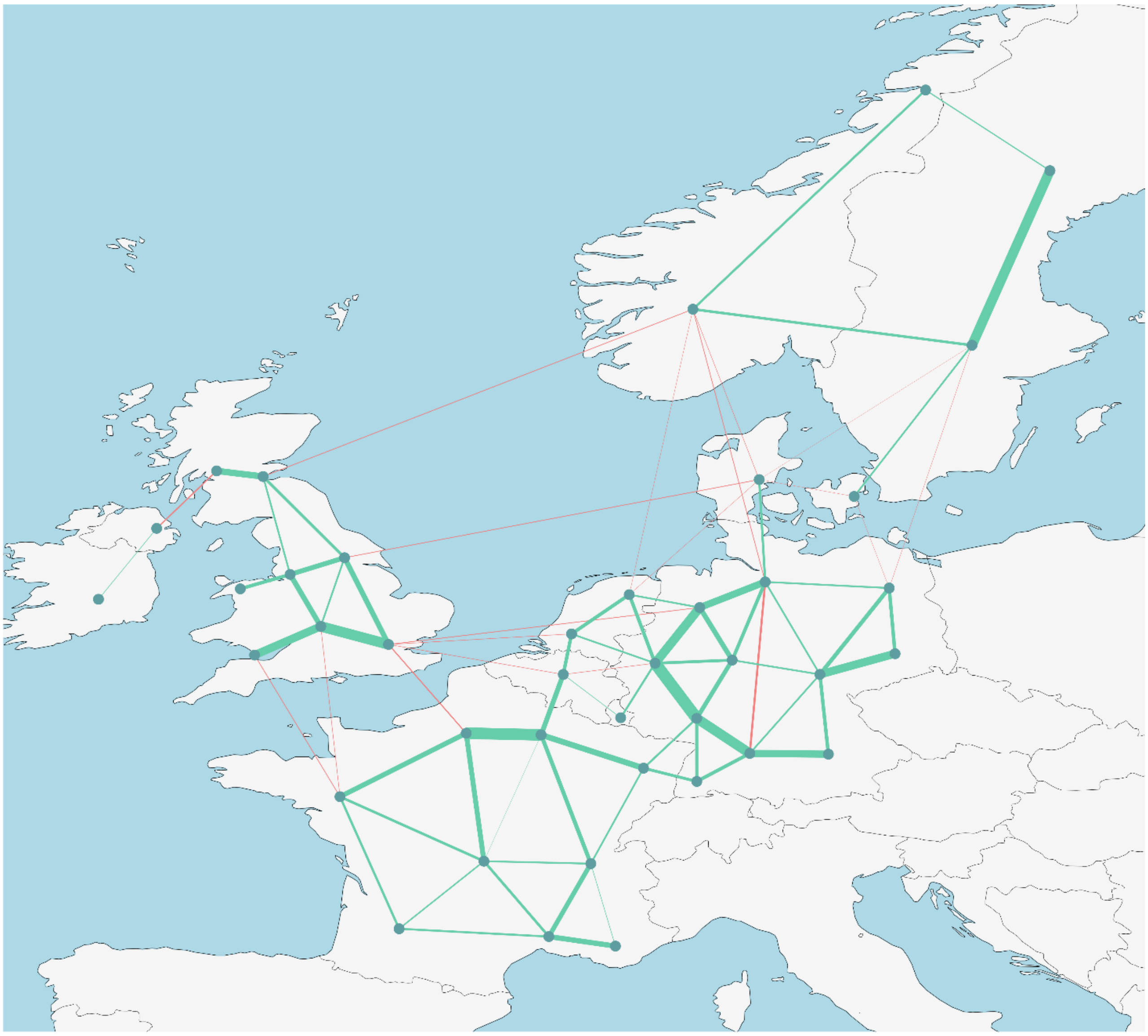

Figure 16: lay-out of the transmission network of scenario 2. In this scenario, no network expansion is allowed.

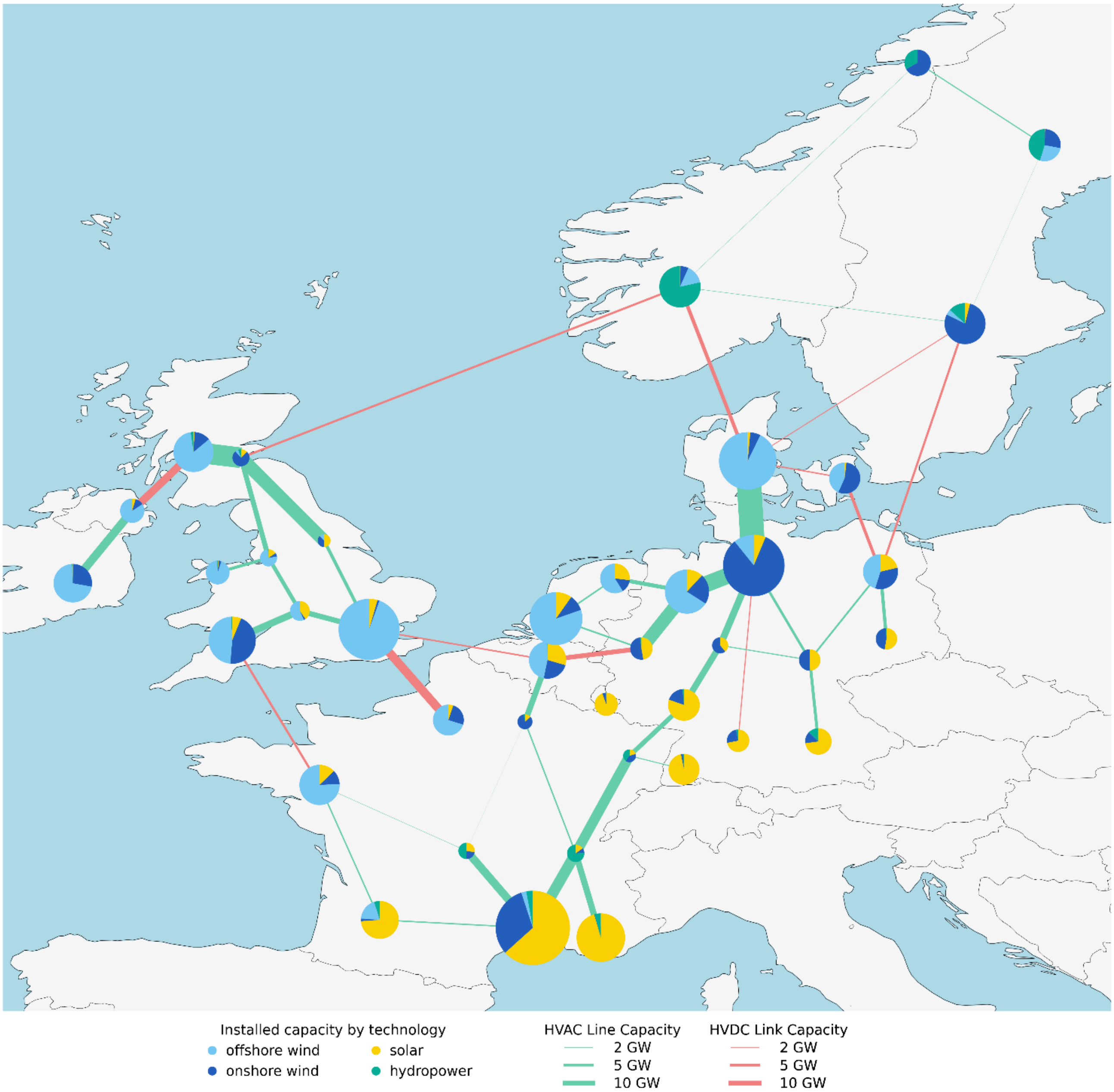

Figure 17: lay-out of the transmission network of scenario 13.In scenario 13, tank storage is used to store hydrogen instead of salt caverns.

E. Modeled electricity generation

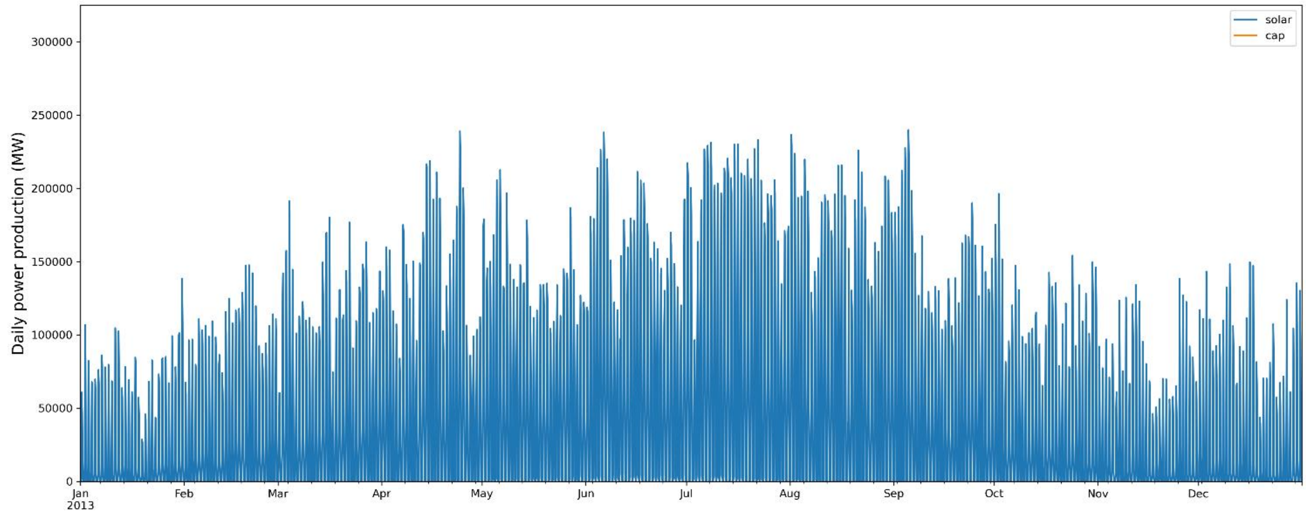

Figure 18: modeled aggregated solar PV electricity generation in the North Sea countries in the baseline scenario. The horizontal orange line denotes the solar PV capacity.

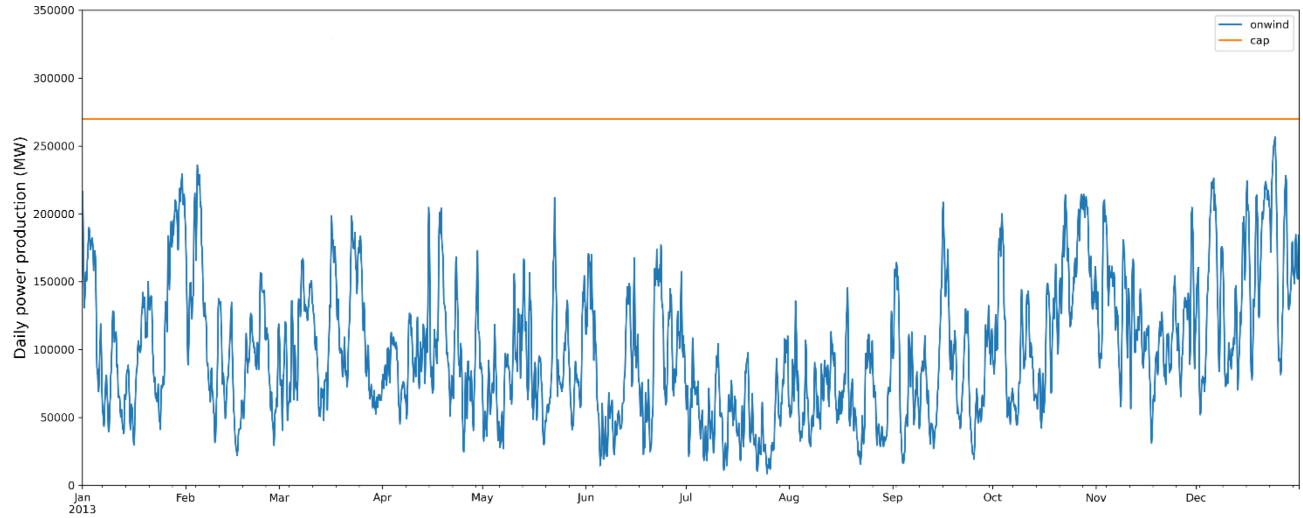

Figure 19: modeled aggregated onshore wind electricity generation in the North Sea countries in the baseline scenario. The horizontal orange line denotes the onshore wind power capacity.

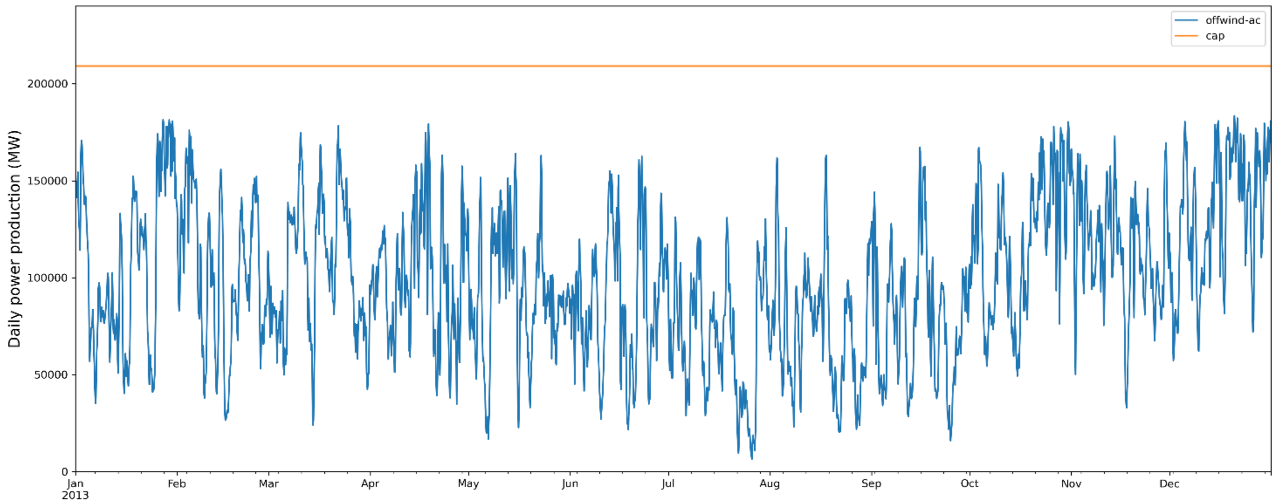

Figure 20: modeled aggregated offshore wind electricity generation connected by AC lines in the North Sea countries in the baseline scenario. The horizontal orange line denotes the offshore wind capacity installed via an alternating current connection line.

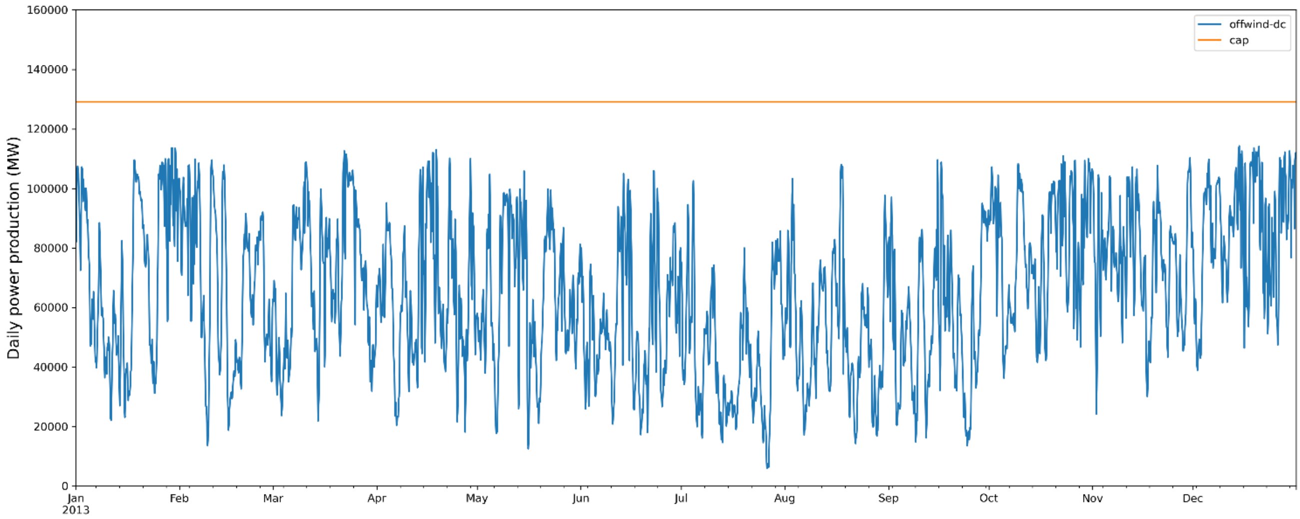

Figure 21: modeled aggregated offshore wind electricity generation connected by DC lines in the North Sea countries in the baseline scenario. The horizontal orange line denotes the offshore wind capacity installed via an alternating current connection line.

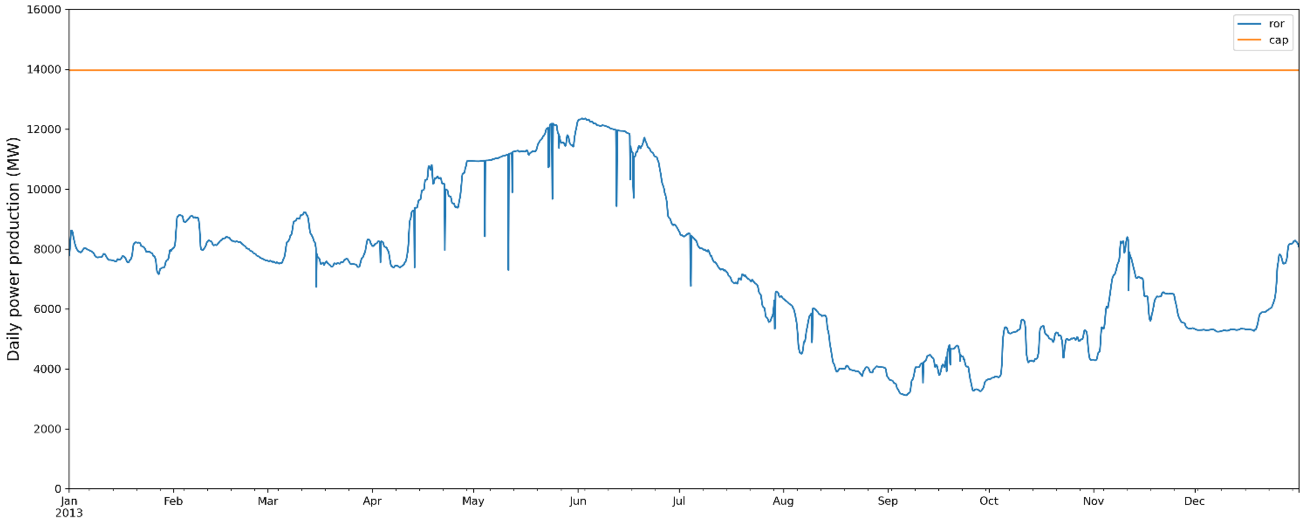

Figure 22: modeled aggregated run-of-river electricity generation in the North Sea countries in the baseline scenario.

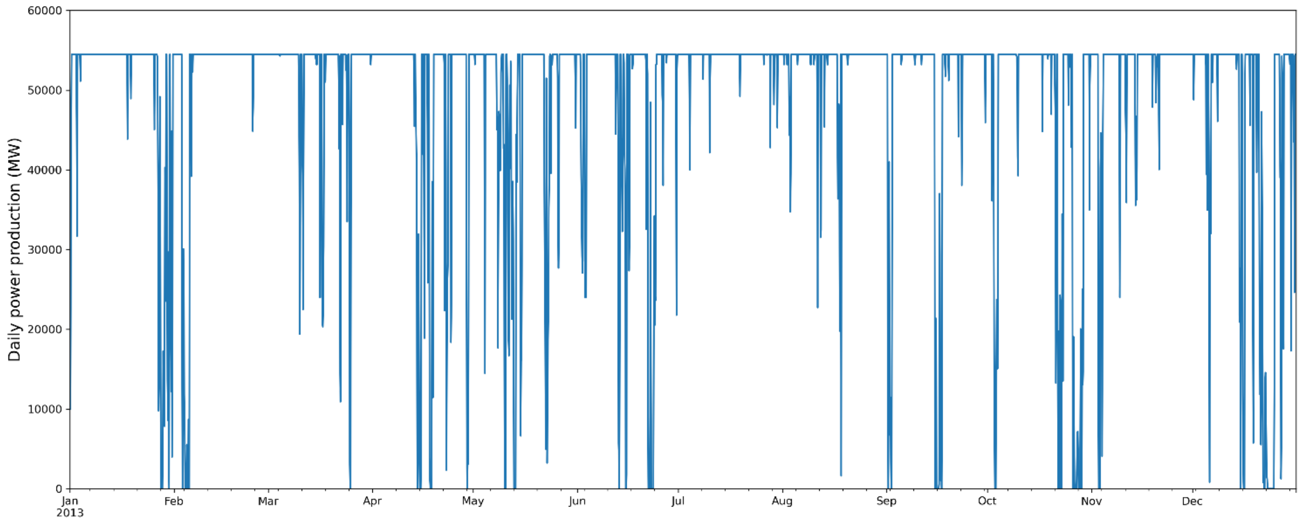

Figure 23: modeled aggregated nuclear power electricity generation in the North Sea countries in scenario 8.

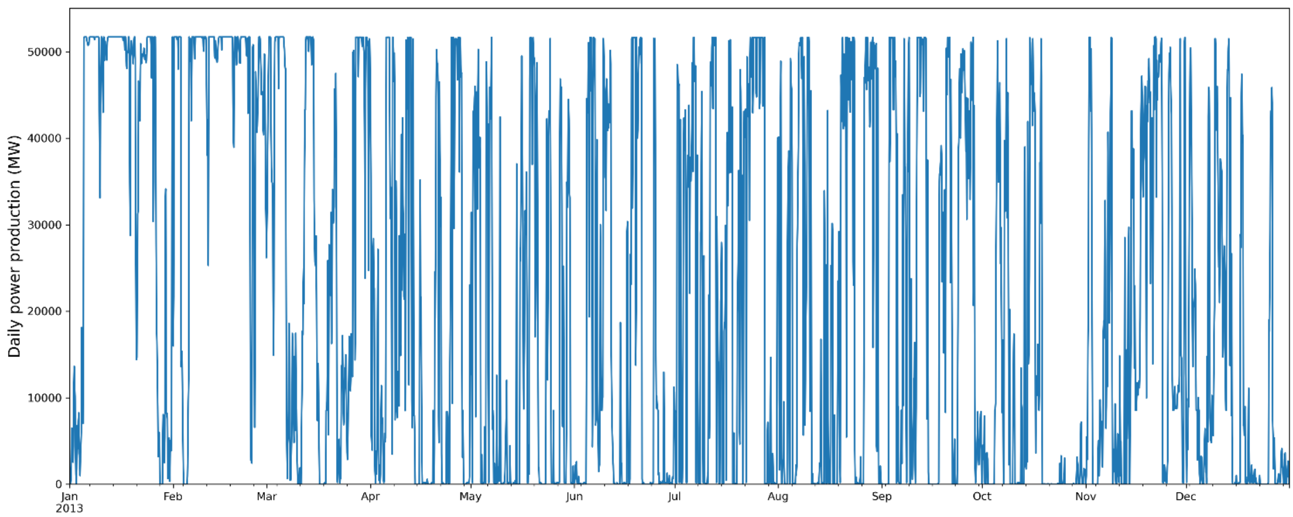

Figure 24: modeled aggregated hydro power electricity generation in the North Sea countries in the baseline scenario.

F. Modeled energy storage

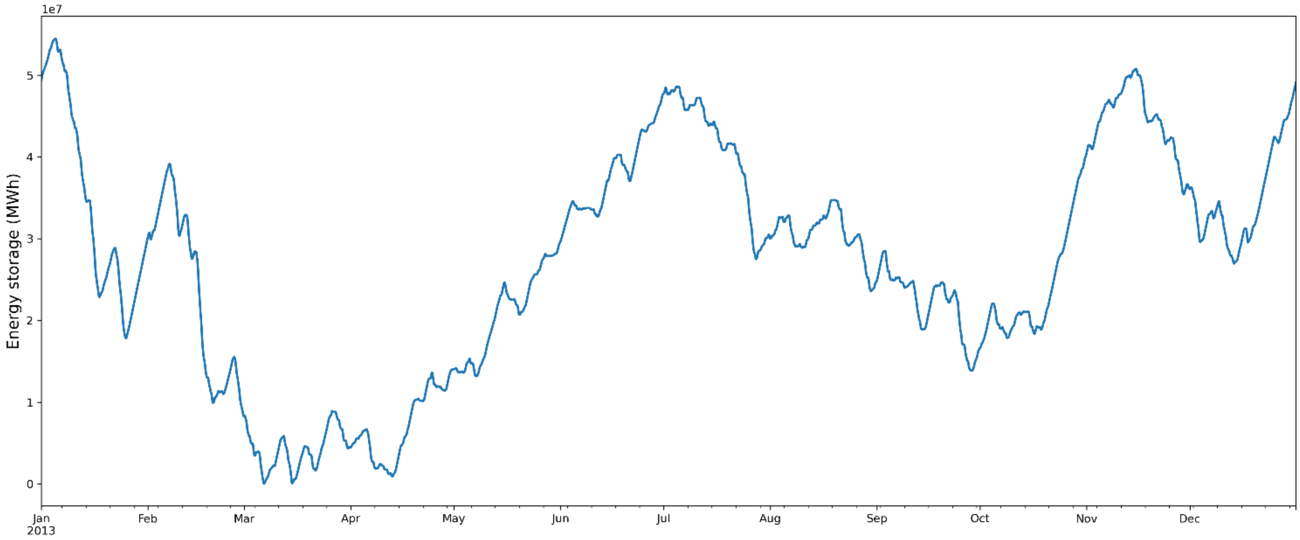

Figure 25: modeled state of charge of the hydrogen storage in the North Sea countries in the baseline scenario.

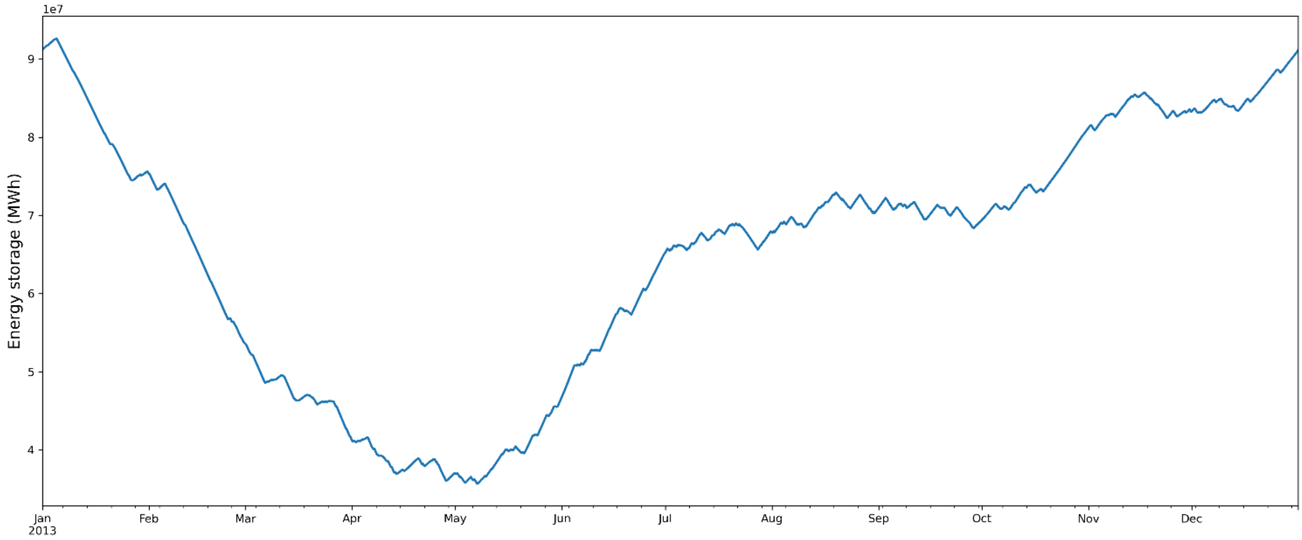

Figure 26: modeled state of charge of the hydropower storage in the North Sea countries in the baseline scenario.

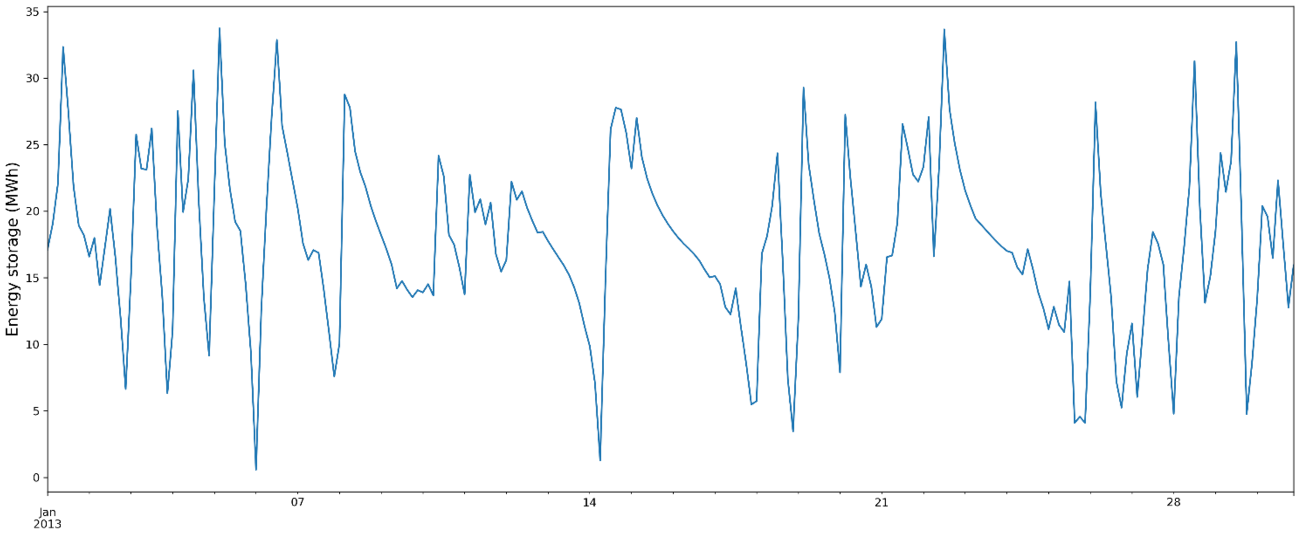

Figure 27: modeled state of charge of battery energy storage in January 2013 in the baseline scenario.

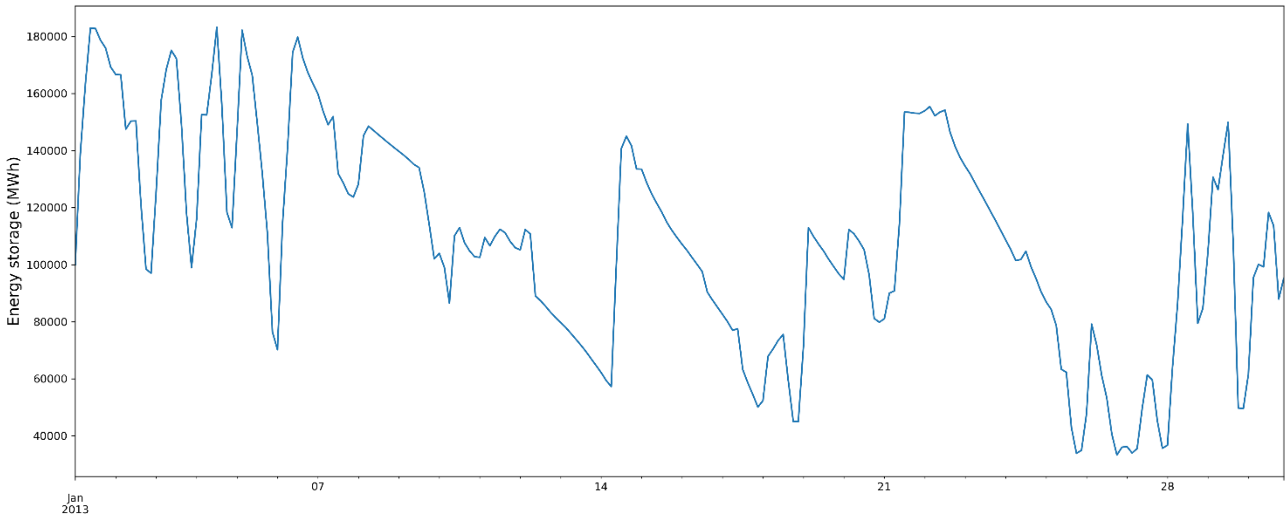

Figure 28: modeled state of charge of the pumped hydro energy storage in January 2013 in the baseline scenario.

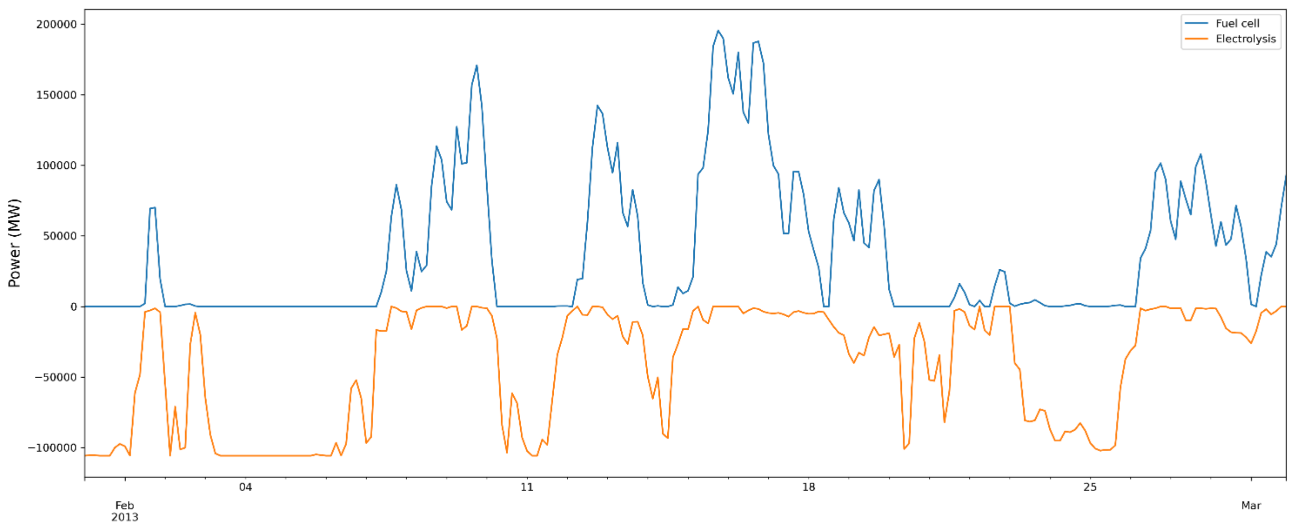

Figure 29: electricity generation of fuel cells by burning hydrogen and electricity consumed to produce hydrogen by electrolyzers in the baseline scenario in February 2013.

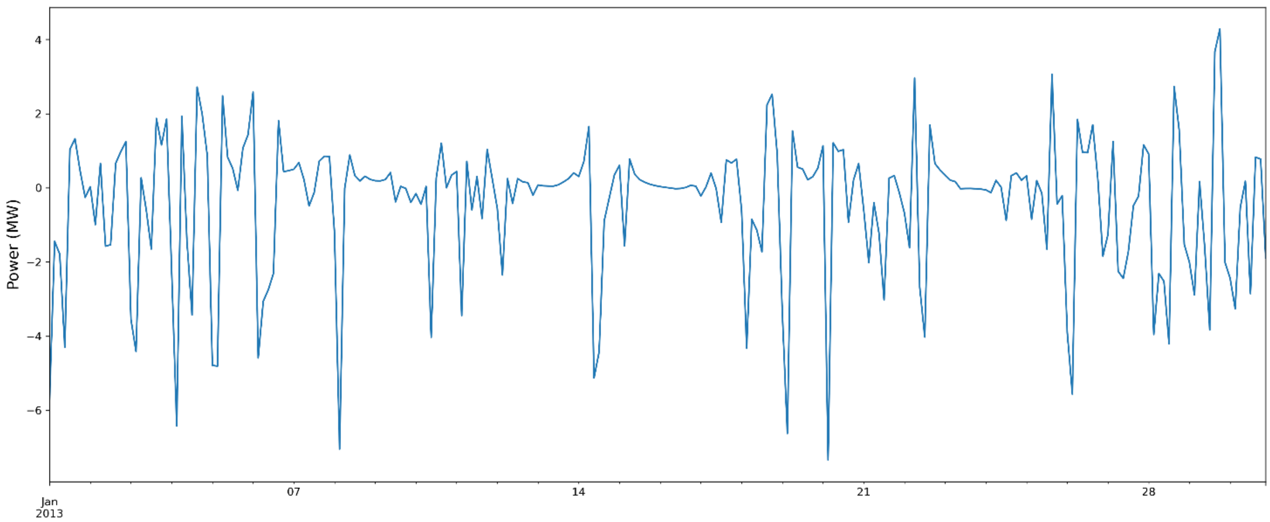

Figure 30: power charging and discharging of batteries in January 2013 in the baseline scenario.

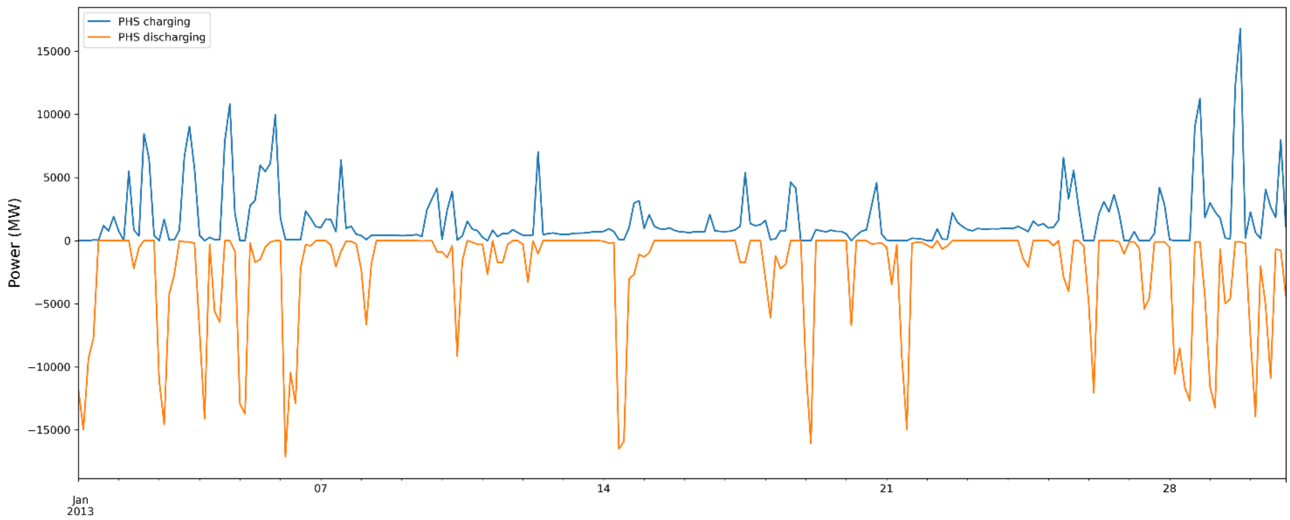

Figure 31: electricity generation and consumption of pumped-storage hydroelectricity in January 2013 in the baseline scenario.

G. Modeling results North Sea countries

Table 35: curtailment of renewable energy in different scenarios as a percentage of total production.

Scenario	Offshore wind-AC	Offshore wind-DC	Onshore wind	Run-of-river	Solar PV
Baseline scenario 40 nodes, 3h res	2.5	4.2	0.4	0.2	0.2
Baseline scenario 40 nodes, 1h res	2.7	3.9	0.4	0.2	0.2
Baseline scenario 40 nodes, 2h res	2.5	4.3	0.4	0.2	0.2
Baseline scenario 40 nodes, 4h res	3.7	2.3	0.4	0.2	0.1
Baseline scenario, 30 nodes, 3h res	4.7	1.5	0.1	0.1	0.6
Baseline scenario, 60 nodes, 3h res	4.4	1.5	0.4	0.2	0.2
Baseline scenario, 80 nodes, 3h res	3.3	2.8	0.2	0.5	0.5
Baseline scenario, scaled historic load	2.5	5.6	0.3	0.3	0.3
Scenario 1	2.6	2.7	0.8	0.0	1.2
Scenario 2	3.0	2.2	0.5	0.1	0.2
Scenario 3	3.4	2.5	0.5	0.3	0.2
Scenario 4	2.7	3.4	0.4	0.2	0.2
Scenario 5	1.9	3.8	0.4	0.1	0.2
Scenario 6	4.4	1.6	0.4	0.1	0.2
Scenario 7	3.5	2.1	0.4	0.3	0.3
Scenario 8	1.3	1.4	0.4	0.1	0.1
Scenario 9	0.2	0.5	0.2	0.0	0.1
Scenario 10	0.6	1.0	0.3	0.1	0.1
Scenario 11	4.1	1.8	0.4	0.2	0.2
Scenario 12	3.5	2.7	0.4	0.2	0.2
Scenario 13	14.0	5.7	0.5	0.0	0.4
Scenario 14	3.3	3.5	0.4	0.2	0.2
Scenario 15	4.3	5.4	0.3	0.1	0.1
Scenario 16	4.3	5.8	0.4	0.2	0.1
Scenario 17	8.5	9.2	0.6	0.3	0.3
Scenario 18	4.3	6.6	0.4	0.2	0.1
Scenario 19	1.9	3.6	0.4	0.2	0.2
Scenario 20	3.7	1.9	0.4	0.2	0.3
Scenario 21	3.4	2.4	0.6	0.4	0.8
Scenario 22	8.3	6.6	1.8	0.2	0.1
Scenario 23	4.2	4.7	0.7	0.3	0.9
Scenario 24	3.9	2.5	0.4	0.2	0.1

Table 36: aggregated capacity [GW] of power plants categorized per technology in the North Sea countries.

Scenario	Offshore wind-AC	Offshore wind-DC	Onshore wind	Solar PV	Nuclear	Hydro-power	Run-of-river	Fuel cells imported H_2
Baseline scenario 40 nodes, 3h res	209	129	270	351	0	52	14	0
Baseline scenario 40 nodes, 1h res	212	128	270	348	0	52	14	0
Baseline scenario 40 nodes, 2h res	211	129	270	350	0	52	14	0
Baseline scenario 40 nodes, 4h res	206	128	270	357	0	52	14	0
Baseline scenario, 30 nodes, 3h res	211	129	270	348	0	52	14	0
Baseline scenario, 60 nodes, 3h res	200	130	270	351	0	52	14	0
Baseline scenario, 80 nodes, 3h res	193	131	270	344	0	52	14	0
Baseline scenario, scaled historic load	199	137	270	361	0	52	14	0
Scenario 1	121	187	270	618	0	52	14	0
Scenario 2	161	178	270	369	0	52	14	0
Scenario 3	164	168	270	352	0	52	14	0
Scenario 4	177	163	270	375	0	52	14	0
Scenario 5	176	191	270	413	0	52	14	0
Scenario 6	180	216	270	454	0	52	14	0
Scenario 7	206	126	270	342	4	52	14	0
Scenario 8	128	110	270	263	55	52	14	0
Scenario 9	98	61	270	200	97	52	14	0
Scenario 10	208	130	270	352	0	52	14	0
Scenario 11	206	132	270	355	0	52	14	0
Scenario 12	203	134	270	361	0	52	14	0
Scenario 13	263	124	270	273	0	52	14	0
Scenario 14	207	121	282	351	0	52	14	0
Scenario 15	255	144	245	239	0	52	14	0
Scenario 16	173	113	270	368	0	52	14	180
Scenario 17	91	104	270	304	0	52	14	247
Scenario 18	167	112	270	366	0	52	14	190
Scenario 19	185	201	270	404	0	52	14	0
Scenario 20	210	260	270	466	0	52	14	0
Scenario 21	247	334	270	719	0	52	14	0
Scenario 22	77	67	527	377	0	52	14	0
Scenario 23	183	113	270	534	0	52	14	0
Scenario 24	305	83	244	305	0	52	14	0

Table 37: net electricity exports [TWh] of each North Sea country in different scenarios.

Scenario	NLD	BEL	DNK	FRA	DEU	IRL	LUX	NOR	SWE	GBR
Baseline scenario 40 nodes, 3h res	7	-5	207	-57	-201	-6	-4	-20	22	56
Baseline scenario 40 nodes, 1h res	15	-5	204	-62	-201	-13	-4	-20	21	66
Baseline scenario 40 nodes, 2h res	7	-2	209	-61	-201	-10	-4	-21	22	62
Baseline scenario 40 nodes, 4h res	0	-6	197	-30	-197	-13	-4	-20	21	52
Baseline scenario, 30 nodes, 3h res	11	1	206	-61	-193	-6	-4	-18	3	62
Baseline scenario, 60 nodes, 3h res	4	1	196	-41	-205	-1	-4	-10	12	48
Baseline scenario, 80 nodes, 3h res	-9	-9	207	-44	-203	-4	-4	2	8	57
Baseline scenario, scaled historic load	14	-2	204	-54	-201	-5	-4	-20	21	47
Scenario 1	60	-19	25	-37	-81	-1	-4	-7	7	56
Scenario 2	144	-31	128	-118	-213	-9	-4	-17	15	104
Scenario 3	97	-27	271	-56	-324	-1	-12	-19	20	51
Scenario 4	25	-23	241	-97	-204	2	-4	-20	17	63
Scenario 5	-76	-24	319	-93	-208	0	-4	-24	20	90
Scenario 6	-133	-23	346	-77	-208	2	-4	-26	20	102
Scenario 7	20	-3	196	-54	-199	-6	-4	-20	22	48
Scenario 8	-21	-2	90	76	-204	-12	-4	-20	19	78
Scenario 9	-43	-21	8	236	-193	-12	-4	-33	49	12
Scenario 10	18	-3	199	-64	-199	-5	-4	-21	22	55
Scenario 11	41	-2	185	-62	-197	-5	-4	-20	21	43
Scenario 12	55	3	180	-74	-190	-6	-4	-20	16	40
Scenario 13	-42	-2	135	-5	-187	23	-3	-43	30	93
Scenario 14	16	-3	201	-49	-200	-6	-4	-20	22	44
Scenario 15	32	-12	242	-105	-214	2	-4	5	-10	63
Scenario 16	19	2	230	-62	-193	-10	-4	-21	29	9
Scenario 17	19	25	45	45	-151	-6	-3	-7	45	-12
Scenario 18	15	-2	221	-47	-190	-11	-4	-21	31	6
Scenario 19	92	-27	238	-139	-225	5	-4	-21	14	66
Scenario 20	131	-30	299	-206	-260	13	-4	-26	9	76
Scenario 21	204	-42	384	-268	-325	37	-5	-52	17	50
Scenario 22	-46	-13	67	-3	-76	10	-4	-13	69	9
Scenario 23	14	0	141	9	-196	-12	-4	-20	23	44
Scenario 24	-51	-23	126	-60	-135	7	-4	35	63	41

H. Technology cost assumptions

Table 38: costs assumptions of different power plant technologies in 2030.

Technology	Lifetime [years]	Investment costs [EUR/kWel]	FOM [%/year]	VOM [EUR /MWhel]	Fuel costs [EUR/ MWhth]	Efficiency [%]	Source
Solar rooftop	25	725	2	0.01	-	-	(ETIP PV, 2019; IEA, 2010)
Solar utility	25	425	3	0.01	-	-	(ETIP PV, 2019; IEA, 2010)
Hydropower	80	2000	1	-	-	90	(IEA, 2010; Schröder et al., 2013)
Run-of-river	80	3000	2	-	-	90	(IEA, 2010; Schröder et al., 2013)
Nuclear power	45	6000[65]	-	8	3	33.7	(IEA, 2011; Schröder et al., 2013)
Onshore wind	30	1040	2.45	2.3	-	-	(Danish Energy Agency (DEA), 2016)
Offshore wind	30	1640	2.3	2.7	-	-	(Danish Energy Agency (DEA), 2016)

Table 39: costs assumptions of flexibility technologies in 2030.

Technology	Lifetime [years]	Investment cost	FOM [%/year]	Efficiency [%]	Source
Pumped-hydro electric	80	2000 [EUR/kWel]	1	75	(IEA, 2010; Schröder et al., 2013)
Hydrogen storage (salt cavern)	40	0.84 [EUR/kWel]	-	-	(Cihlar et al., 2021)
Hydrogen storage (tank storage)	20	11.20 [EUR/kWel]	-	-	(Budischak et al., 2013)
Hydrogen fuel cell	20	339 [EUR/kWel]	3	58	(Steward, 2009)
Electrolyzer	18	350 [EUR/kWel]	4	80	(Steward, 2009)
Battery storage	15	192 [EUR/kWh]	-	-	(Budischak et al., 2013)
Battery inverter	20	411 [EUR/kWel]	3	90	(Budischak et al., 2013)

[65] The FOM of nuclear power plants is included in the investment costs.

Table 40: costs assumptions of electric infrastructure technologies in 2030.

Technology	Lifetime [years]	Investment costs	FOM [%/year]	Source
HVAC overhead	40	400 EUR/MW/km	2	(Hagspiel et al., 2014)
HVDC overhead	40	400 EUR/MW/km	2	(Hagspiel et al., 2014)
HVDC submarine	40	2000 EUR/MW/km	2	(Hagspiel et al., 2014)
HVDC inverter pair	40	150000 EUR/MW	2	(Hagspiel et al., 2014)
Offwind ac-station	-	250 EUR/kWel	-	(Danish Energy Agency (DEA), 2016)
Offwind ac-connection submarine	-	2685 EUR/MW/km	-	(Danish Energy Agency (DEA), 2016)
Offwind ac-connection underground	-	1342 EUR/MW/km	-	(Danish Energy Agency (DEA), 2016)
Offwind dc-station	-	400 EUR/kWel	-	(Härtel et al., 2017)
Offwind dc-connection submarine	-	2000 EUR/MW/km	-	PyPSA-Eur estimation (Hörsch, Hofmann, et al., 2018)
Offwind dc-connection underground	-	1000 EUR/MW/km	-	(Härtel et al., 2017)

I. Overview of citations used in literature study

Table 41: extended documentation of the citations used in Chapter 4.

Table	KEV 2021 (PBL, 2021)	Werkgroep extra opgave (Werkgroep Extra Opgave, 2022)	KIVI 2020 (Persoon et al., 2020)	II3050 (Netbeheer Nederland, 2021)	TNO 2022 (Scheepers, Palacios, Janssen, et al., 2022)	TYNDP 2022	A Clean Planet for All (European Commission, 2018)	TYNDP 2022 Europe (ENTSOG & ENTSO-E, 2022d)	European green deal: Fit for 55
Table 4	p.236, p.159, p.144	p.12, p.15	p.25	p.25-29	p.28, p.21	-	-	-	-
Table 5	p.221, p.138	-	p.25	p. 5-28	p.221, p.138	(ENTSOG & ENTSO-E, 2022a)	p.68, p.72	p.21	(Directorate-General for Energy, 2021a, 2021b, 2021c)
Table 6	p.175, p.229, ETM	p.12	p.26	p.29, ETM	p.21, p.28, p.54	-	-	-	-
Table 7	p.111	p.12	p.25	p.25-29, p.107	p.74, p.76	-	-	-	-
Table 8	p.236, ETM	p.12	-	p.25-29	p.28, p.47-48, p.54-55	-	-	-	-
Table 9	p.134, p.217	p.12	-	p.25-28	p.30, p.35, p.59 p.73,	-	-	-	-
Table 10	p.105, p.234	p.18, p.6	p.25	p.25-28, p.133	p.19, p.30, p.84	(ENTSOG & ENTSO-E, 2022b)	-	-	-

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