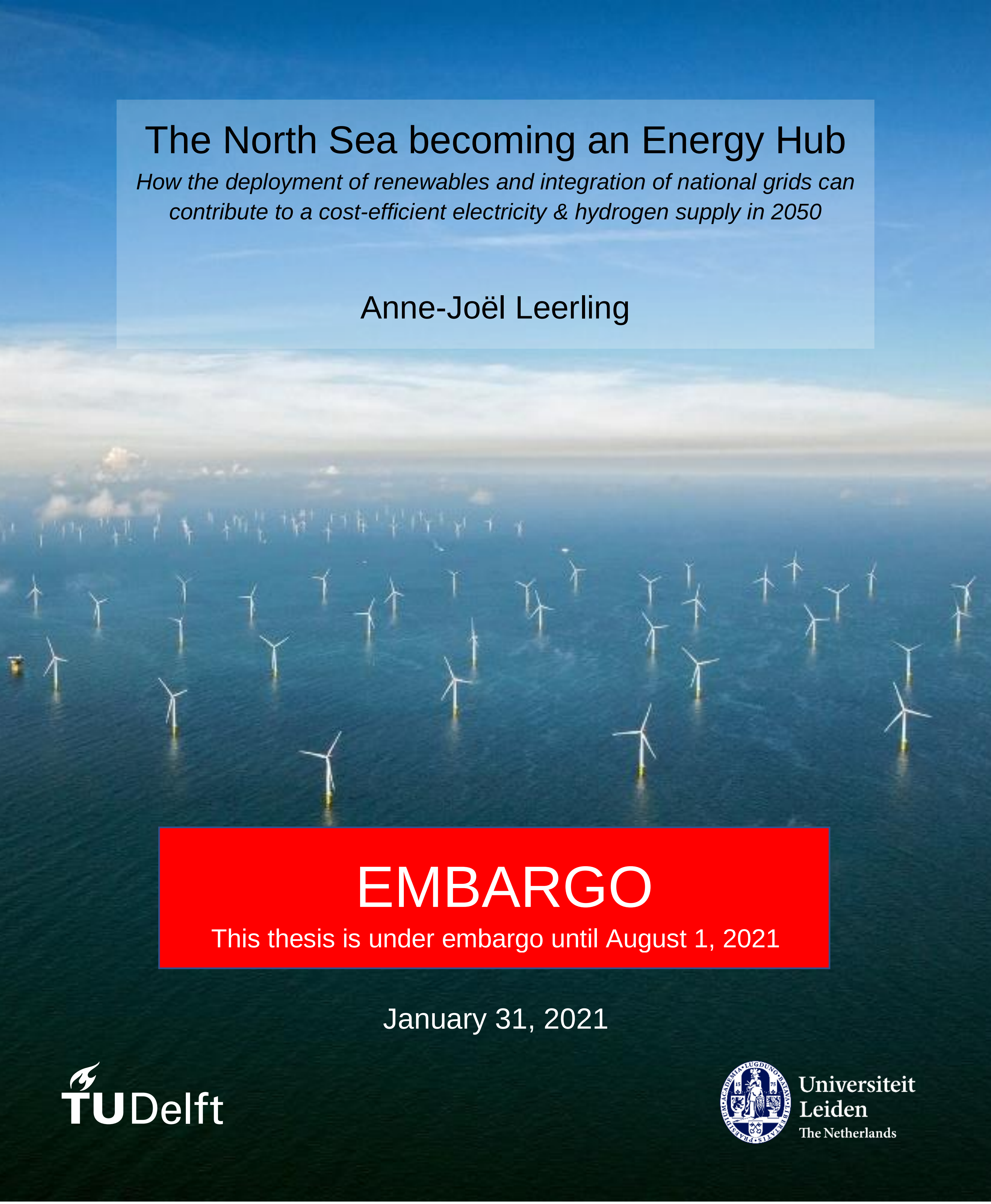

The North Sea becoming an Energy Hub

How the deployment of renewables and integration of national grids can contribute to a cost-efficient electricity & hydrogen supply in 2050

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EMBARGO

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How the deployment of renewables and integration of national grids can contribute to a cost-efficient electricity & hydrogen supply in 2050

By

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In partial fulfilment of the requirements for the degree of

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SUMMARY

To fight the threat of global warming, nations worldwide are currently in the transition towards a renewable-powered energy system. One of the main technologies represented in a renewable-powered energy system is wind energy. Rapid developments in the offshore wind sector caused the rise of offshore wind farms in the North Sea and more wind farms are expected for the years to come. As this renewable-powered energy system will be heavily dependent on the availability of wind and solar energy, great challenges will arise to the security of supply in the energy system. To tackle this challenge, nine countries surrounding the North Sea (called NSEC) cooperate on researching a cost-efficient energy system design which enables the large-scale deployment of wind and solar energy. One aspect that hasn't been researched for the NSEC so far is the potential of hydrogen for this energy system. Hydrogen can play an important role in the future renewable energy system as fuel and feedstock for different sectors and as energy carrier that allows for seasonal storage. The question of what energy system design choices bring the most cost-efficiency for the NSEC, considering the hydrogen and electricity demand in 2050, will be researched.

For this research, results have been based on optimizing the future energy system in the simulation modelling program Powerfys. This model optimizes power plant utilization while taking the constraints assigned to the power plants and to the energy system infrastructure into account. Powerfys operates on a rolling planning on the intra-day and the day-ahead market. The model consists of 50 nodes, divided over 9 countries and the North Sea. By simulating scenarios focused on either renewable energy capacity expansions or transmission infrastructure design, different levels of cost-efficiency are determined. These outcomes will allow to answer the research question.

This research shows that a cost-efficient energy system for both electricity and hydrogen in the NSEC can exist with the current planned electricity and natural gas transmission grid for 2050, assuming a fully retrofitted natural gas grid, exclusively utilized for hydrogen transmission. What this study does show is that extensive amounts of offshore wind (285 GW) and other renewables (245 GW of onshore wind and 434 GW of PV) must be deployed, to meet the expected electricity and hydrogen demand of 2050. For offshore wind this means that not only the potential of bottom-fixed wind turbines should be accounted for, but also the potential of the novel technology of floating wind turbines must be considered. On top of that, this study shows that only 4 to 5% of all hydrogen demand must be imported from outside NSEC. Even without the imports of any hydrogen, meeting full electricity and hydrogen demand would be technically possible, but this would lead to higher energy system costs for the deployment of higher capacities of renewables and the storage for hydrogen in salt caverns. Though, the sensitivity analysis shows that hydrogen imports can increase significantly when price levels related to hydrogen (import-, electrolyser- or hydrogen storage prices) will turn out different in 2050 than currently expected. Nevertheless, this research also shows that such a significant increase in hydrogen imports will not lead to remarkable deviations in the overall energy system design or the energy system costs.

PREFACE

Despite the challenging circumstances in the year 2020, I am now at the brink of finishing my MSc. Industrial Ecology. The process of writing my thesis has been completely different than I could have expected at the start. Where I was prepared for writing my thesis at the office of Guidehouse in Utrecht, the reality of the corona pandemic made this impossible. Instead, I have been writing my thesis from home like so many others have worked from home this year.

Even though the collaboration with Guidehouse turned out different than I expected, I am grateful for the support that they have provided me with during the course of writing this thesis. First of all, I would like to thank Barry Vree for supervising me personally. Without his help I would not have been able to immerse myself in the topic of the North Sea Wind Power Hub. Besides that, he has always been helping me out with developing this research greatly. Second of all, I would like to thank Lou Ramaekers, who has been helping me extensively with the modelling and simulating of my scenarios in Powerfys. Explaining me how this worked and what I can use it for was already a challenge under normal conditions but doing this only via video calls made this extra challenging. Therefore, I am very grateful for his help and patience. Besides that, I would like to thank the other colleagues that have been involved in the development of my research. Kees van der Leun, Tobias Fichter, Carmen Wouters and Lennard Sijtsma, thank you for providing me with help during my thesis. Also, I would like to thank all other colleagues at Guidehouse for making me part of the organization and allowing me to gain knowledge outside the scope of my own research. I have been able to get to know several interesting projects that the firm works on and it allowed me to gain a further understanding of the development in the energy industry and in the field of sustainability.

Of course, I would also like to thank my supervisors of TU Delft for their guidance in my thesis. Kornelis Blok, thank you very much for your feedback and insights that you have provided over the course of this thesis. Also, I would like to thank Mart van der Meijden for his guidance during my thesis. His insights and questions have been triggering me to develop my research further. I would like to thank both for providing me with feedback that has brought this thesis to a higher level.

Last of all, I would like to thank my parents and my girlfriend for their support. Especially my girlfriend, that moved one month before the pandemic from Prague to our apartment in Rotterdam. Even though the year turned out completely different than we could have expected our first year of living together, I cherish the time that we have been able to spend together. On top of that, your love and support has helped me to stay motivated despite these challenging times.

Anne-Joël Leerling, December 2020

List of tables

LIST OF FIGURES

List of abbreviations

AE	Alkaline water Electrolysis
BEV	Battery-electric vehicle
CAPEX	Capital Expenditures
CO_2	Carbon dioxide
ENS	Energy Not Served (% of total energy demand)
GW (GWh)	Gigawatt (Gigawatt hour)
G2P	Gas-to-Power plants
H_2O	Water
kW (kWh)	Kilowatt (Kilowatt hour)
MW (MWh)	Megawatt (Megawatt hour)
NDC	Nationally Determined Contribution
NSEC	North Sea Energy Cooperation (consisting of the Netherlands, Belgium, Luxembourg, Germany, France, United Kingdom, Ireland, Denmark, Norway and Sweden)
NSWPH	North Sea Wind Power Hub
OPEX	Operating Expenditures
PEM	Proton Exchange Membrane electrolysis
PV	Photovoltaics
PW (PWh)	Petawatt (Petawatt hour)
P2G	Power-to-Gas plants
SOEL	Solid Oxide Electrolysis
TW (TWh)	Terawatt (Terawatt hour)

Table of Contents

1. Introduction

The research conducted in this thesis is based on different developments in the renewable energy industry that have been taking place in recent years. The major developments and concepts that underly the research will be discussed in the following chapters. The topics are the Paris Agreement, the developments in offshore wind, the North Sea Wind Power Hub and the promise of hydrogen. This introduction section will be closed with the research objectives and research questions that will be covered in the following research.

1.1 The Paris Agreement

Currently the world is facing the threat of climate change. This threat leads to global warming and the disturbance of existing ecosystems. To mitigate climate change, nations have been working towards its mitigation. After several conferences in previous years, 2015 marked the most significant milestone so far in the international combat against worldwide climate change.
On December 12 in 2015, the Paris Agreement was signed. This agreement states the following:

"The Paris Agreement central aim is to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius." (UNFCCC, 2020)

The agreement, which entered force on November 4, 2016, has currently been signed by 189 out of 197 countries in the world (UNFCCC, 2020). In the agreement, countries are required to set nationally determined contributions (NDCs) to drastically reduce the amount of greenhouse gasses emitted. The goal is to bring global greenhouse gas emissions back to nearly zero in the year 2050. Greenhouse gasses are trapping and holding heat in the atmosphere, which can then lead to an increase in so-called global warming. By reducing greenhouse gasses, this greenhouse-effect can be limited, resulting in a reduction of global warming.

The greenhouse gas that is merely responsible for this greenhouse effect on Earth is carbon-dioxide. Carbon-dioxide, here-after called CO_2, is mostly emitted during the combustion process of fossil fuels, in order to produce energy.

CO_2 emissions started to increase after the First Industrial Revolution, around 1850. In these times, the society in Europe changed from one consisting of mainly agriculture and handicrafts to one dominated by industrial and manufacturing processes. While processes in the agricultural and handicrafts' society were mainly executed by man's power, industrial and manufacturing processes were powered by the combustion of the fossil fuels coal and oil (Haigh, 2017).

After 1950, CO2 emissions started rapidly increasing. The increasing world population, growing economic welfare and the upcoming consumption society are the main drivers for the rapid increase in CO_2 emissions in the post-World War II era.

When focusing on the most recent decades, four main sectors contribute for the far majority to the emissions of greenhouse gasses. The sectors with the largest impact to this date, is the electricity & heat production industry. The majority of the electricity and heat produced worldwide is by fossil-fueled power plants. Those plants combust fossil fuels, such as coal and gas, in order to generate electricity and heat for residential or commercial purposes. The second largest industry contributing to this date is the transportation industry. This industry concerns all road, maritime and aviation transportation taking place worldwide. Another sector heavily contributing to CO_2 emissions is the industrial sector. These emissions occur during industrial processes, which are powered by fossil fuels. Examples of industries causing significant contributions to CO_2 emissions are the iron & steel industry and the cement industry.

In order to limit the amount of emitted CO_2 emissions a radical transition from a fossil fuel-based energy system towards a renewable-based energy system must take place in the following decades. Renewable sources are sources producing energy without requiring fossil fuels to be combusted and therefore without CO_2 emissions.

The worldwide challenge for the upcoming decades is to create a renewable energy system that can supply energy for the growing world economy without requiring the need of combusting fossil fuels while emitting CO_2. If that is achieved, the goals of the Paris Agreement can be achieved, and the threat of global climate change can be limited.

1.2 The developments in offshore wind

For creating a renewable energy system, renewable energy technologies are crucial to supply the demanded energy. Despite the promise of many novel technologies as wave, tidal and geothermal energy, the two dominant renewable energy technologies to date are solar and wind energy. Both technologies have been facing tremendous developments in efficiency, production volumes and production costs in the past decades.

When looking at Europe, especially the Northern part of the continent, wind energy seems to be most promising to supply a large amount of the energy that is demanded (Bilgili, Yasar, & Simsek, 2011). Wind is an abundant source in many countries, especially in the coastal regions. Another advantage of wind energy is that wind turbines do not have a large footprint. This means that it does not necessarily compete with other forms of land use.

In the past decades wind turbines on an industrial scale have been developed for onshore purposes. The first turbine of 1 MW was built in 1941 in the United States. Nevertheless, it

took another decade until the first megawatt-scale wind turbine was developed that was connected to a utility grid (Allamehzadeh, 2016).
Because of the oil crisis in the 1970s, wind energy was seen for the first time as an alternative source of energy for the until then dominant fossil fuels. Nevertheless, it took until the 1990s when governments started to encourage the development of wind energy, by providing support schemes, as a response the raising concerns of climate change (Flowcut, n.d.).

From then on, also offshore wind turbines were developed. The pioneering country in offshore wind is Denmark. In 1991 this country developed the first offshore wind farm. This farm consisted of 11 wind turbines of each 450 kW (Dismukes & Upton, 2015). The support of the national government and the investments made by DONG Energy, now called Ørsted, caused rapid developments in the deployment of offshore wind turbines. Offshore wind farms didn't only start producing more electricity because of the increasing amount of wind turbines per wind farm. What's more is that offshore wind turbines made rapid improvements in power production per turbine. The first offshore wind turbines in 1991 consisted of turbines producing less than half a megawatt, while 25 years later turbines were deployed of 8 megawatts.

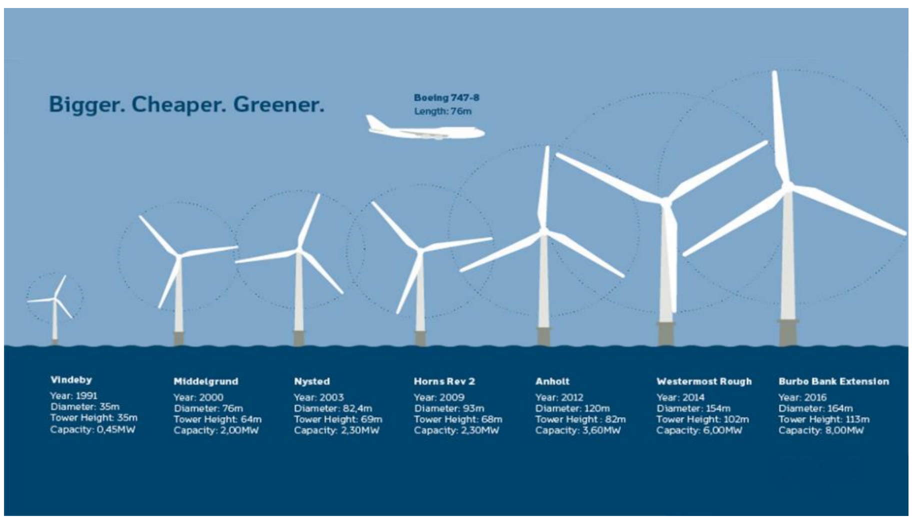

FIGURE 1 - TECHNOLOGICAL DEVELOPMENT OF OFFSHORE WIND TURBINES (ORSTED, 2016)

When looking at the most recent developments in offshore wind, even turbines with double digits are being deployed. The most recent development in the power production of offshore wind turbines is the announcement of a 14-megawatt turbines, with short-term power boosts of 15 megawatt possible, by the firm Siemens Gamesa. This turbine is expected to be available for deployment in offshore wind farms from 2024, 33 years after the deployment of the first offshore wind farm (Siemens Gamesa, 2020).

Because of the rapid development in offshore wind in the past decades, a total amount of 22 GW was deployed in Europe until 2019, on a total of 28 GW worldwide (Sönnichsen, 2020). In addition to that, a total of 170 GW of onshore wind turbines have been deployed only in

Europe (WindEurope, 2020). Though wind turbines onshore are currently more dominant in the energy system of most European countries, a further increase in offshore wind turbines is expected in the upcoming decades. Reasons for that are the potential lower costs of energy produced (LCOE) for offshore wind turbines compared to onshore, the local objection against wind turbines onshore and the higher variability of wind speeds onshore compared to offshore.

One of the reasons why the offshore wind energy is currently not reaching its full potential is the limitation that turbines are so far only being deployed in shallow waters. This is because wind turbines must be fixed on the seabed. The operation of deploying these so-called bottom-fixed turbines is only limited to waters where the water depth is approximately 50 meters or less (EEA, 2009). These shallow waters are available in countries such as Denmark, Germany, The Netherlands and The United Kingdom. Unfortunately, many countries in Europe located at the Mediterranean Sea and the Atlantic Sea and countries in other continents have not been able to deploy wind farms so far. This is because they do not have shallow waters available which are far enough off-coast to limit visual impact from shore.

In recent years, a novel technology will allow for deployment of wind turbines on deeper waters. The development of floating wind turbines, turbines that are no longer fixed to the seabed but are floating on a buoyant platform, enable offshore wind farms to be deployed in waters with deep waters (Maienza, et al., 2020). This will enable a further increase in the potential of offshore wind turbines. According to a recent report of the World Bank, the potential for floating offshore wind is two times bigger than the potential deployment of bottom-fixed offshore wind (Buljan, 2020). With these developments, offshore wind energy can become a dominant source of renewable energy around the globe.

Many experts previously believed large floating wind projects would be developed only after companies had exhausted sea beds suitable for fixed-bottom turbines. But there are now indications that “these things are going to be developed in parallel”, according to a director at Equinor (Thomas N. , 2020).

More technological developments and a further decrease in costs in the offshore wind industry is expected. With the increasing urge for a switch to a renewable energy system, offshore wind will play a more significant role in the energy mix of countries for the following decades. A study commissioned by WindEurope, estimated a total of 450 GW of offshore wind deployment in Europe, of which 337 GW can be deployed in the North Sea (WindEurope, 2019).

1.3 The North Sea Wind Power Hub

The North Sea has already proven to be a suitable location for the deployment of offshore wind turbines to date. Out of the total 22 GW of installed capacity of offshore wind in 2019 in

Europe, only less than 500 MW was not installed in the North Sea but in other European seas Wind (WindEurope, 2020) .

There are several reasons for this high rate of deployment in the North Sea. One of the reasons for this is because of the low water depth in large areas of the sea, which enables the construction of offshore wind turbines (Cruciani, 2018). Also, the North Sea offers an excellent wind regime (high wind speeds with low variability) and the countries surrounding the North Sea have a high demand for energy. On top of that, the development of offshore wind farms has been supported by financial support-schemes from national governments. Also, the available offshore infrastructure and expertise in countries like Denmark, the United Kingdom and The Netherlands plays a role.

Until now, all the deployed offshore wind farms on the North Sea are located near the shore and are therefore relatively easy to be connected to existing infrastructure on land. Nevertheless, wind turbines (and most other renewable energy sources) provide a non-dispatchable generation of electricity. In the following decades, the share of non-dispatchable energy generators is expected to increase, as many dispatchable energy generators (such as fossil-fuel power plants) are expected to be closed. This can potentially endanger the security of supply.

Different solutions can contribute to maintaining a high reliability of the electricity network, while increasing the share of non-dispatchable renewable energy sources. First, storage solutions can contribute by buffering energy when there is more supply than demand, while this buffered energy can be released when demand exceeds the supply. Secondly, demand response solutions allow energy consuming industries or appliances to consume electricity depending on the available supply at that moment. Thirdly, the reliability of the network can be increased by increasing the interconnectivity of the network with neighboring networks. This means that during potential electricity shortages, electricity can be imported from foreign networks. This increase in flexibility contributes to the reliability of both interconnected electricity networks.

FIGURE 2 - ARTIST IMPRESSION OF ENERGY-HUB AS PROPOSED BY TENNET IN 2016 **(VAN DER MEIJDEN M. , 2016)**

For this solution, international coordination for the deployment of offshore wind and the development of an interconnected electricity network for countries surrounding the North Sea has been proposed. The first proposal for this international coordination and the development of a so-called 'energy-hub' has been made in 2016 by Tennet. In the same year, a joint declaration by the North Sea Region Countries (Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden) established the North Seas Energy Cooperation (NSEC) (European Commission, 2020). The aim of NSEC is 'to facilitate the cost-effective offshore renewable energy, in particular wind, and promoting interconnection between the countries in the region'. The countries belonging to NSEC are the above-mentioned countries being part of the North Sea Region Countries. The United Kingdom has been a member of NSEC, but since the 31st of January 2020, it has left the NSEC as a result of Brexit.

In early 2020, a feasibility report, commissioned by the NSEC consortium, has been presented. This report considered the power system for 2050 of NSEC (including the United Kingdom) surrounding the North Sea. This study proposed a hub-and-spoke concept of several energy-hubs in the North Sea, called North Sea Wind Power Hubs (NSWPH, 2019). Via these hubs different national electricity networks can be interconnected, as shown in Figure 3. In addition to that, these hubs could facilitate the deployment of electrolysers. Electrolysers can convert the offshore wind electricity to hydrogen gas, which can then be transported by gas pipelines to the shore. According to the presented study, which has been carried out by Guidehouse (Ecofys / Navigant), a coordinated roll out of these energy-hubs in the North Sea can accelerate the deployment of offshore wind. This can be done to maintain the security of supply for the electricity network for the lowest societal costs (Navigant, 2020).

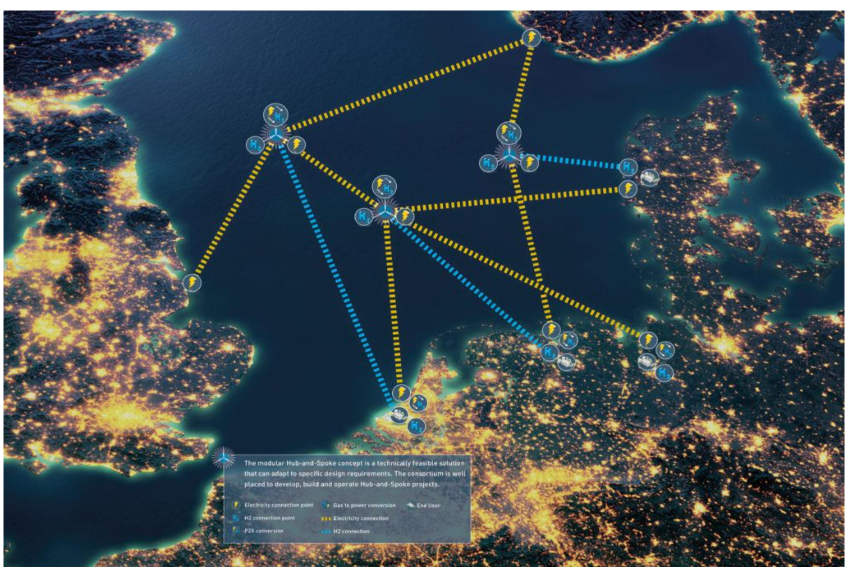

FIGURE 3 - ILLUSTRATION OF HUB-AND-SPOKE CONCEPT **(NSWPH, N.D.)**

The presented hub-and-spoke system consists of modular hubs that can be developed in accordance with the developed offshore wind energy in the North Sea (NSWPH, 2019). It does not only allow for an interconnected electricity grid, which will benefit the security of supply for the countries surrounding the North Sea, but it will also allow the development of hydrogen production and transmission offshore. By the production of hydrogen offshore, the existing gas infrastructure can be utilized, and electricity grid reinforcement can be limited.

1.4 The promise of hydrogen

One of the main drivers of the transition towards a fully zero-carbon energy system in the following decades is the electrification of different sectors. This means that operations that are currently being powered by a fuel, will be powered by electricity in the future. An example of an industry which is currently in the process of electrification is the passenger mobility sector (Roelofsen, Somers, Speelman, & Witteveen, 2020). Electricity can be produced by renewable energy sources, such as wind and solar energy. Besides that, electricity is more efficient when converting it to kinetic energy than fuel is. Nevertheless, this electrification of the energy industry has different limitations and challenges.

First of all, not all industries are expected to be able to become electrified (Gas for Climate, 2019). For instance, electricity does not have the ability to heat furnaces of several industrial processes, as the required amount of heat cannot be achieved by electricity. On top of that, storage solutions for electricity, such as battery storage, have very limited energy density. Therefore, sectors as the aviation industry and long-distance road transport are not expected to be electrified in the near future.

As just mentioned, electricity has a limited capability to be stored for usage at a later moment in time. The energy density is relatively low (compared to currently available storage alternatives) and the storage of electricity for longer periods of time is not expected to be cost-efficient in the following decades. Though, the storage of electricity for later use will become increasingly important as the share of renewable energy in the total energy mix increases. Renewable energy sources, such as wind and solar energy, have the major drawback that they are not available on demand, but depending on the weather conditions. To prevent major energy deficits in energy systems relying on renewable energy sources, other storage solutions must be utilized simultaneously.

One of the promised solutions for these challenges is the application of hydrogen. Hydrogen is a gas that has been used for centuries for different industrial applications (IEA, 2019). The major reason why hydrogen is perceived as the energy carrier which will play a key role in the transition towards a renewable energy system, is because hydrogen can be produced by electricity (The world of hydrogen, n.d.). In its productions process, called electrolysis, H2O atoms are split into pure oxygen and hydrogen. Hydrogen produced by the process of electrolysis, when powered by renewable energy, is called green hydrogen. This process of electrolysis can also be powered by fossil fuels, resulting in the emissions of CO_2. Hydrogen produced by fossil fuels is called grey hydrogen, as this process is still causing greenhouse gas emissions. Another method to make hydrogen out of fossil fuels is called steam methane reforming. Also, this process is considered as grey hydrogen. Nevertheless, both of these processes can be made carbon-neutral, by capturing the greenhouse gasses before emissions. After capturing, these gasses are being stored. This process, where fossil fuels are still required but no greenhouse gasses are emitted, is called blue hydrogen.

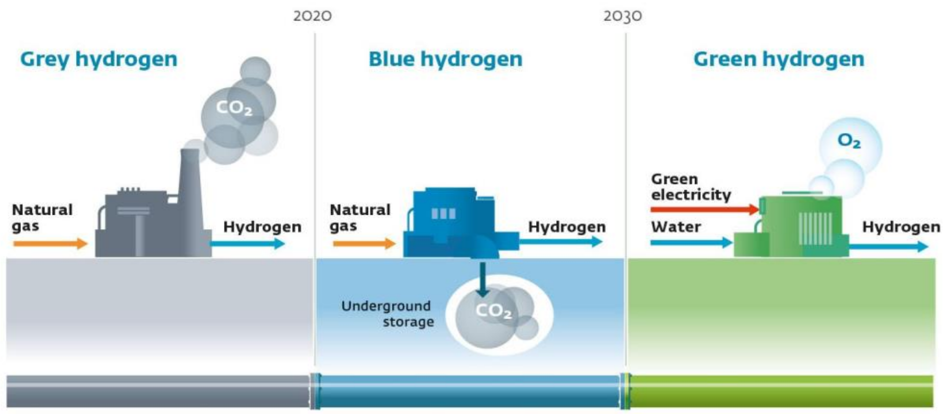

FIGURE 4 - DIFFERENT FORMS OF HYDROGEN (THE WORLD OF HYDROGEN, N.D.)

As a gas, hydrogen is an energy carrier with a significantly higher energy density than the storage applications of electricity. On top of that, the storage costs are lower and more scalable. Therefore, a more feasible solution for storing electricity can be by converting it to hydrogen and storing that in large-scale facilities. When the electricity demand is higher than the supply, the stored hydrogen can be re-processed back to electricity and meet the gap between supply and demand. These conversion processes are called Power2Gas (P2G) and Gas2Power (G2P) installations.

Another advantage of hydrogen is the significant lower cost of transportation than for electricity (Vermeulen, 2017). When comparing the transportation of hydrogen by pipelines to electricity by power cables, a significant difference can be perceived. Because of this, it can be interesting to convert amounts of energy that has to be transported over long distances from electricity to hydrogen. This could lead to a more cost-efficient energy system.

Based on these advantages, the applications of hydrogen can play an important role in the development of the North Sea Wind Power Hub. The applications, the storage potential and the possibilities for cheap energy transportation of hydrogen allows it to have a complementary contribution in the intra-national infrastructure by the NSEC.

1.5 Research questions

As major deployments of renewable energy sources in and around the North Sea are expected to emerge in the following decades, infrastructure has to be developed that can guarantee security of supply for this region. The hub-and-spoke concept as proposed by the North Sea Power Hub consortium is expected to play a central role in this development. The scope of the executed study by Guidehouse, mentioned in Chapter 1.3, on the North Sea Wind Power

Hub has been on the development of offshore wind and the interconnectivity of electricity infrastructure among different countries. This neglects the demand for other energy sources than electricity in those countries and it does not consider the increasing interest, technological developments and potential demand in hydrogen.

Hydrogen is an enabler for decarbonization of several sectors and for long-term energy storage in the energy system. To what extent hydrogen will play a role in the energy system of the NSEC in 2050 and to what extent this hydrogen can be produced within NSEC, is still unknown. Therefore, the main aim of this research is to investigate to what extent the potential hydrogen demand can be met in NSEC and what energy system design choices related to electricity and hydrogen contribute to a cost-efficient energy system, considering both the electricity and hydrogen infrastructure, of the NSEC in 2050.

Thus, the objective of this research is to determine the feasibility of meeting both the electricity and hydrogen demand for 2050 in NSEC and to investigate which designs of transmission and storage infrastructure result in the most cost-efficient design of the infrastructure.

In accordance with the mentioned research objective, the following main research question can be derived:

What energy system design choices contribute to a cost-efficient energy system for the NSEC in 2050, when considering the electricity and hydrogen demands for 2050?

In order to determine the most cost-efficient energy system for the NSEC in 2050, different possible design choices, or scenarios, have to be researched. By reviewing and comparing the impacts of these different infrastructural designs, a most desirable system design can be distinguished. In order to set up different energy system designs a set of sub research questions has been made as a starting point. The determined sub research questions are the following:

1. To what extent is the deployment of offshore wind and onshore renewables necessary to meet the demanded electricity and hydrogen in the NSEC by 2050?
2. How can the import of hydrogen from outside NSEC contribute to a cost-efficient energy system in the NSEC for 2050?
3. How can the expansion of the electricity grid or hydrogen grid contribute to a cost-efficient energy system in the NSEC for 2050?
4. To what extent can the deployment of electrolysers on inland locations contribute to a cost-efficient energy system in the NSEC 2050?
5. To what extent can the deployment of electrolysers on offshore locations contribute to a cost-efficient energy system in the NSEC 2050?

2. THEORETICAL BACKGROUND

Prior to the research that has been conducted, a theoretical background is provided. In this theoretical background, academic literature and secondary sources from public authorities and research institutes is discussed on the main topics of this thesis. First, energy system models are discussed in Chapter 2.1. The discussed literature provides a starting point by explaining energy system modelling and the different scopes of previous research that has been conducted. Following to that, a theoretical background on hydrogen as energy carrier is provided in Chapter 2.2. In Chapter 2.3, a literature review is presented on previous research that has been conducted on generating electricity and producing hydrogen on the North Sea. Subsequently, the potential use cases of the hydrogen gas are presented in Chapter 2.4. Then, a theoretical background is provided about the infrastructure that is required to transport hydrogen. In this chapter, Chapter 2.5, also the differences with the differences with the electricity infrastructure are discussed. Last of all, the relevance of this study to the field on Industrial Ecology is explained in Chapter 2.6.

2.1 ENERGY SYSTEM MODELS

In multiple academic studies it has been concluded that high shares of renewable energy in the European electricity system are both technically feasible and affordable (Brown, Slachtberger, Kies, Schramm, & Greiner, 2018) (Brown, et al., 2018) (Gils, Scholz, Pregger, Luca de Tena, & Heide, 2017). Those findings are based on energy system models. Energy system models are suitable for advising policy makers on the development of the energy system in one or multiple regions (Zakeri, et al., 2016). Energy system models allow a long-term planning of the system by considering a certain amount of time slices of a given year. The main aim of the modelling exercise is to optimize the infrastructural capacity expansion in the considered regions over a given number of years. This is done from the perspective of a central planner. Models developed of the electricity system can provide important insights about the cost-effectiveness of several combinations of energy technologies given by environmental, societal or physical constraints that are modelled (Slachtberger, Brown, Schäfer, Schramm, & Greiner, 2018).

Different studies have been conducted on the future of the European electricity system by energy system modelling. They state that a fully renewable electricity system can be achieved in a cost-effective way by expanding the current transmission network among countries (Brown, et al., 2018) and by deploying energy storage facilities (Gils, Scholz, Pregger, Luca de Tena, & Heide, 2017). The developed models for scenario-development consist of models focusing on either the pan-continental transmission network or on sector coupling. A pan-continental transmission network entails the integration of electricity markets across the entire continent to smoothen out weather variations in different countries (Brown, Slachtberger, Kies, Schramm, & Greiner, 2018).

Nevertheless, these studies that cover Europe, or at least multiple countries in Europe, only consider the electricity system in the scope of their research. By neglecting other existing energy systems, such as the gas system, design choices that may be most desirable for the entire energy system, are not considered in a study. Combining the optimization of the electricity system together the gas system allows for sector coupling. Sector coupling entails the integration of different systems such as electricity and gas system (Robinius, et al., 2017). By integrating those systems in the model, significant cost-reductions can be achieved as the gas system can provide forms of flexibility for the electricity system (Hagspiel, et al., 2014).

The studies that have integrated different energy systems in their model only take a limited geographical resolution. For instance, the study by Robinius et al. (2017) uses sector coupling by creating a model where the electricity system is integrated with the transport sector. Nevertheless, the spatial resolution considers only Germany, which means that there is no pan-continental transmission network entailed in the study. The research of (Brown, Slachtberger, Kies, Schramm, & Greiner, 2018) distinguishes itself by combining both the pan-continental integration of the European electricity market and the sector coupling in one model. However, this model takes the electricity market as its primary system whereas hydrogen only serves as a storage solution for storing excesses of generated electricity by renewable energy technologies, which can be used for moments of generation shortages. This means that demand for hydrogen in sectors such as the industrial and mobility sector are not considered. In case these would be considered, different system designs for both the electricity system and gas system could be recommended.

Therefore, the development of a model where both the electricity system as the gas system on a cross-country resolution can provide new insights in the cost-effective pathways towards the future energy system. North-Western Europe has been researched in different energy system model studies before, but no study provided a model where both the electricity and gas system are integrated and equally represented for a pan-continental resolution. A study considering the developments of electrification and a transition towards hydrogen including intercontinental transmission network, can lead to new insights on the design of the energy system in North-Western Europe.

2.2 Hydrogen as energy carrier

Hydrogen is a molecule, consisting of two hydrogen atoms. This gaseous formation can also be called an energy carrier, which means that it can contain energy that can be converted in a later stage to other forms of energy (Rosen & Koohi-Fayegh, 2016). Nevertheless, hydrogen is not a primary energy source. It can only be created by production from a primary energy source as electricity or fossil fuels. Therefore, hydrogen is also called a secondary energy carrier. Hydrogen is perceived as an ideal clean energy carrier because of its high energy density, high calorific value and variety of methods for long-term storage (Guo, Li, Zhou, & Liu, 2019). Another important characteristic of hydrogen is that it can be considered as complementary to electricity, which means that hydrogen can be made from electricity, but also that this hydrogen can be converted back from hydrogen to electricity (Scott, 2007).

This is critical for the application of hydrogen. Hydrogen is, in contrast to electricity, easily stored and transported (Pudukudy, Yaakob, Mohammad, Narayanan, & Opian, 2014). This makes it an enabler for energy-demanding practices that are challenging or not feasible to be electrified in the future.

Hydrogen has been a gas that has been used for centuries already, mainly in the industrial sector. The main industrial processes where hydrogen is already used in large quantities are in ammonia production, petroleum refining and methanol production (Balat, 2008). Many times in history, it has been perceived as the promising substitute for the current fossil fuels, but until now hydrogen has not been able to live up to its promises. The major reason for his is that hydrogen hasn't been cost-competitive compared to fossil fuels so far (Abe, Popoola, Ajenifuja, & Popoola, 2019). Nevertheless, in the foreseeable future, this is expected to change. For this, there are three major reasons.

First, the costs of fossil fuels are rapidly increasing since the introduction of carbon taxation. In the European Union, the ETS system has been implemented (Borghesi & Flori, 2018). This system is a market where emissions rights must be acquired in order to emit CO_2. Those emissions right allow industries to emit a certain amount of greenhouse gas emissions, as so-called cap-and-trade system. As the number of available emissions rights is further limited over the years by the European Union, the price of the emission rights is expected to increase (Convery, 2009). As the price of CO_2 emissions, and therefore the price of emitting fossil fuels becomes more expensive, hydrogen becomes a more price-competitive substitute as it can be produced without the emission of CO_2 emissions.

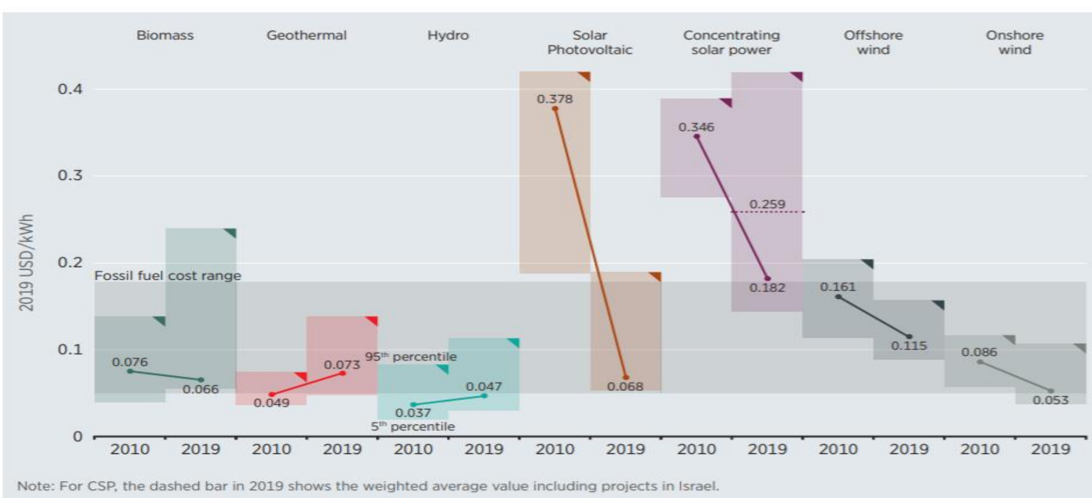

FIGURE 5 - GLOBAL WEIGHTED AVERAGE LEVELIZED COST OF ELECTRICITY FROM UTILITY-SCALE RENEWABLE POWER GENERATION TECHNOLOGIES, FROM 2010 TO 2019 **(IRENA, 2020)**

Second, the cost of electricity production by wind turbines and solar panels, the two major renewable energy technologies, have dropped tremendously (IRENA, 2020). The developments in the past decade are shown in Figure 5. As mentioned previously, renewable energy is required to produce green hydrogen. When looking at the levelized costs of solar and wind energy over the past decades, a significant decrease is shown. The costs are now so low, that the production of electricity by solar and wind power on some locations in the world is now cheaper than electricity production by fossil-fired power plants, such as a coal plant. With a further decrease expected, the price-competitiveness of green hydrogen compared to fossil fuels is expected to improve. Especially when considering the higher generation costs for fossil fuels in the future due to carbon taxing systems.

Nevertheless, the question can be raised if those two developments are sufficient to make hydrogen cost-competitive with fossil fuels as natural gas. Another development that might help this cost-competitive the most, is that governments start to support hydrogen development projects extensively this time. As more governments are understanding the potential of hydrogen for further decarbonization of their economy, they start supporting the development of hydrogen production and infrastructure. The number of countries with policies supporting hydrogen technologies is increasing along with the number of sectors which are being supported (IEA, 2019).

As the costs of fossil fuels for energy generation are increasing, the price of electricity generation by renewable energy sources is decreasing and the amount of policy incentives for hydrogen technologies is also increasing, it is expected that hydrogen can become the fuel of the future for many different industries.

2.3 Offshore energy on the North Sea

As mentioned in Chapter 1.3, the North Sea Wind Power Hub consortium has been executing previous studies on the potential costs and benefits of developing a hub-system in the North Sea, allowing to integrate the energy grid of the NSEC. The first study on the costs and benefits of the design of the North Sea Wind Power Hub has been executed in 2019 by TNO. In this research, four potential locations of an offshore hub-island were studied (Swamy, Saraswati, & Warnaar, 2019). The analysis was based on the evaluation of the potential installation and O&M costs of these potential locations. The aim of the study was not to nominate a preferred location, but only to evaluate the different cost levels among the different potential locations. A year after this study, Navigant published a study that researched the possible grid integration possibilities for the NSEC. This study had a primary focus on the electricity grid, but it allowed sector coupling in its model by producing hydrogen from otherwise curtailed electricity. This hydrogen could be stored and be used, after conversion, at moments that electricity demand transcended the electricity production. This was all considered assuming a copper-plate model for both hydrogen transmission and hydrogen storage. The study concluded that combining offshore wind farm electricity grid connections with the (international) electricity market connections provides significant cost advantages to the electricity grid of the NSEC compared to an electricity grid without this combination. This combination can be utilized by developing 'hybrid offshore transmission assets', earlier mentioned as offshore hub-islands, which allow for the distribution of electricity among different countries. On the other hand, the study also shows that long-term storage of energy, by hydrogen, is required to develop this combined electricity system with the most cost-efficient design. Not only the storage is required, but also the conversion and re-conversion of electricity intro hydrogen must be developed on a large scale.

As mentioned, the study of Navigant primarily focussed on the electricity grid and the electricity demand; it therefore only allowed offshore wind energy to be transported onshore by electricity cables in their study. Nevertheless, other studies have already researched if there are more cost-efficient transportation methods for bringing the energy onshore. One of these studies was conducted by the New Energy Council. This study states that by 2050, significant cost reductions can be achieved when converting hydrogen offshore, near the offshore wind farms on so called energy-conversion islands, instead of transmission from offshore to onshore by electricity transmission (New Energy Council, 2020). On the other hand, this study also states that in 2030, these cost-efficiencies cannot be achieved yet, as P2G-conversion offshore in combination with hydrogen transmission is still too expensive compared to electricity transmission. Important remark of this study is that it only looked at the conversion and transportation costs, while neglecting the entire electricity & gas infrastructure of the NSEC.

As offshore hydrogen transmission is considered as potential cost-saving method of transmitting energy from offshore to onshore, pilot projects have been announced recently. One of these pilot projects is the PosHYdon pilot, carried out by TNO & Neptune Energy (Energy Industry Review, 2020). In this pilot, a P2G-conversion plant will be located on an existing oil & gas platform 10 kilometres out of the coast of The Hague. Another development is that Siemens Gamesa, one of the leading manufacturers of offshore wind turbines, recently announced the development of an offshore wind turbine which includes an integrated electrolyser (Steitz, Käckenhoff, & Eckert, 2021). The turbine, of 14 MW, is expected to have a one-MW electrolyser integrated and expected to be commercially available by 2025.

As shown, different studies foresee an important role in hydrogen production from electricity produced by offshore wind turbines. In the following decade hydrogen production will be most cost-efficient onshore, but it is expected that offshore will be more cost-efficient by 2050. Yet, no research so far has executed how the developments of hydrogen production for 2050 can be integrated cost-efficiently in the design of the electricity & gas infrastructure system of the NSEC. Therefore, this study can provide new insights on a more systems level.

2.4 Potential hydrogen demand

Hydrogen can substitute the use of fossil fuels in the three major energy-demanding sectors: the industrial sector, the transportation sector and the heating sector (Staffell, et al., 2019).

The heating sector consists of energy consumption related to the heating of residential and commercial buildings. Decarbonization of this industry is perceived as difficult for different reasons. One of the major reasons is that the requirements for decarbonization are diverse, as the characteristics of different types of buildings in different regions require different solutions (Staffell, et al., 2019). For some buildings, electrifying the heat demand can be the optimal solution, while this might not be a feasible solution for other type of buildings in areas with a different climate. Hydrogen is expected to play a role in the decarbonization of this sector. However, because of the complexity in this sector, it is still very uncertain in what order of magnitude hydrogen will become a substitute for the current heating sources of residential and commercial buildings (Chaudry, Abeysekera, Hosseini, Jenkins, & Wu, 2015).

For the industrial sector and the transportation sector, the zero-carbon substitutes are more limited. In the industrial sector, some processes can be electrified, but for many other industrial processes this is not feasible. As mentioned before, hydrogen has been used for decades already in the industrial sector. The application of hydrogen in the sector can be further extended when decarbonization is required, as hydrogen can replace the use of natural gas in burners and fuels for several industries (Vogl, Åhman, & Nilsson, 2018). However, hydrogen can also be the substitution for high-temperature industries such as cement and steelmaking (Thomas, Edwards, Dobson, & Owen, 2020).

In the transportation sector, hydrogen is also expected to play a crucial role in decarbonization. As noticed in recent years, battery-electric vehicles (BEVs) are emerging rapidly in the passenger car segment (Ahmadi, 2019). Though, it is not expected that BEVs will be a viable solution for the transportation of heavy freight over long distances. For that, hydrogen can be the enabler. For the maritime, not many solutions have been proved as viable zero-carbon alternatives to the current practices (Balcombe, et al., 2019). The same accounts for the aviation industry. In this sector hybrid-electric applications are being tested for short-haul flights, whereas biofuels are being mixed in lower degrees with kerosene so far (Schäfer, et al., 2019). In both industries, hydrogen is expected to play a role, but to what extent seems to be unclear so far.

2.5 Hydrogen infrastructure

As mentioned in the previous chapter, hydrogen is an energy carrier that is easily transported and stored, in retrospect to electricity. The essence of the production, transmission and storage of hydrogen are further explained. This theory forms the foundation for the assumptions that are made in the conducted research of this report.

2.5.1 PRODUCTION OF GREEN HYDROGEN

For the production of green hydrogen, renewable energy has to be produced. The energy, electricity produced from renewable energy sources such as wind turbines and solar panels, powers the process of electrolysis. The process of electrolysis splits water molecules into hydrogen and oxygen by using renewable energy. This can visualize in the following chemical reaction:

$$2H_2O \rightarrow 2H_2 + O_2$$

There are three technologies for the process of electrolysis: Alkaline water electrolysis (AE), Proton Exchange Membrane electrolysis (PEM) and Solid Oxide Electrolysis (SOEL) (Brauns & Turek, 2020). The first two mentioned technologies are advanced and mature technologies, while the last technology is still in a development stage. For both the AE and PEM technology, the electrolysis process can currently take place with an efficiency of around 70% (Buttler & Spliethoff, 2018). This means that hydrogen produced by electrolysis contains 70% of the energy initially used as input for the process in electricity. The remaining 30%, of which the far majority consists of waste heat, of the energy can be considered as energy losses.

2.5.2 TRANSMISSION OF HYDROGEN

One of the limitations of electricity is the expensive costs of transportation when transporting large amounts over long distances (De Vrieze, et al., 2020). Hydrogen could solve this, as it has characteristics that allow for a better transportation over long distances in large quantities (Taieb & Shaaban, 2019). On top of that, transmission of hydrogen is expected to be possible for a cost which approximately 15 cheaper than the transmission of electricity (Vermeulen, 2017). Just like natural gas, hydrogen is transported by pipelines. The natural gas, also called methane (CH_4), grid that is currently in operation allows to a large extent for suitability of hydrogen transmission. This can save significant costs compared to the development of a new-built hydrogen-dedicated grid (Guidehouse, 2020). However, a refurbishment of the transmission infrastructure is required. This is because hydrogen had a lower density and viscosity than methane (Tabkhi, Azzaro-Pantel, Pibouleau, & Domenech, 2008). This means that without a refurbishment, hydrogen could escape from the pipelines that are designed for the transmission of methane.

The existing transmission network of natural gas pipelines in Europe is shown in Figure 6. This map shows the topology of the entire transmission infrastructure on an intra-national and cross-border level. The map clearly shows the high degree of international integration of the natural gas infrastructure. This makes the transport for hydrogen in the future on an international level more suitable.

FIGURE 6 - THE TRANSMISSION INFRASTRUCTURE OF THE NATURAL GAS GRID IN NORTH-WESTERN EUROPE **(ENTSOG, 2019)**

2.5.3 Storage of hydrogen

Besides the transportation of hydrogen, the storage of hydrogen is essential. In contrary to electricity infrastructure, gas infrastructure allows the storage of energy. Pipelines don't require a constant static pressure to maintain the performance of the infrastructure (De Vrieze, et al., 2020). Gas infrastructure allows for a flexible pressure with a minimum and maximum of pressure. This enables for the storage of hydrogen in gas infrastructure. Nevertheless, this storage is only feasible for short-term purposes and for the absorption of short-term fluctuations in demand.

When considering the seasonal demand fluctuations that have to be anticipated, other solutions have to be discussed. For the storage of hydrogen on a large-scale for seasonal fluctuations in demand, salt caverns are considered as the most cost-effective solution (Zakeri & Syri, 2015). The largest potential for the storage of hydrogen in Europe lays in the utilization of salt caverns. Salt caverns allow for the storage of large amounts of hydrogen storage. These large amounts of storage are necessary to supply demand in weeks and months when it cannot be met by the produced amount of hydrogen.

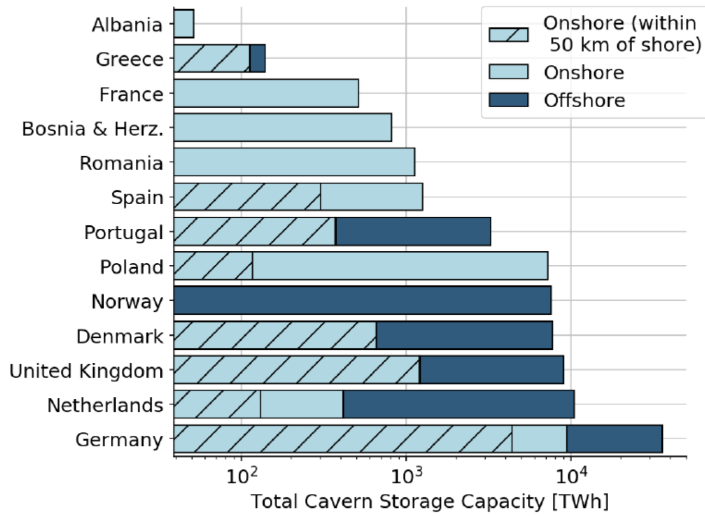

FIGURE 7 - TOTAL CAVERN STORAGE CAPACITY FOR HYDROGEN
(CAGLAYAN, ET AL., 2020)

Most of the countries of the NSEC have salt caverns that can potentially store large quantities of hydrogen (Caglayan, et al., 2020). This assessment to identify the technical potential of hydrogen storage capacities in salt caverns is based on a suitability assessment of salt formations in Europe, while considering land eligibility constraints as urban areas and natural protected areas. For the suitable salt caverns, the estimated technical storage capacity is determined. According to this assessment, a total technical potential capacity of 84.8 PWh of hydrogen can be stored in salt caverns located in European countries. The technical storage capacities per country and per location is shown in Figure 7. Nevertheless, a large amount of this storage capacity (77%) is located offshore and therefore difficult to become ever operational. Of this total amount, 27% consists of salt caverns that are located on shore. On the other hand, not all onshore locations of salt caverns can be considered as eligible either. As shown in the figure above, a distinction has been made between onshore locations located at a maximum of 50 kilometers of the shore and other onshore locations. The reasons for this distinction are economic and environmental constraints related to the construction of the salt cavern. During the construction of the cavern, a brine solution that is located in the cavern has to be disposed in large amounts. The salt content of this brine solution is too high for disposal in lakes and rivers; therefore, the sea is the only disposal location. A location near shore of the salt cavern is therefore required.

When taking these constraints into account and only consider near shore onshore locations, Denmark (650 TWh), the United Kingdom (1200 TWh), The Netherlands (120 TWh) and Germany (4500 TWh) are the four countries of all NSEC that have a potential to store hydrogen in salt caverns. In total, this is still a total of 6470 TWh of technical potential of hydrogen storage in salt caverns.

2.5.4 Import of hydrogen

It might occur that at some moments the generation of renewable energy in the NSEC is insufficient to meet the electricity and hydrogen demanded in those countries. Also, it could be that the import of hydrogen from regions outside of the NSEC is cheaper than the production of it in the NSEC. A reason for this could be because of the lower generation costs of a kilowatt of electricity. The main region which is expected to provide Europe with hydrogen via imports is Northern-Africa, according to the Gas for Climate study (Gas for Climate, 2019). This study estimates the maximum technical potential in the Sahara for solar green hydrogen on 80,000 TWh per year in 2050. In comparison, the final energy consumption in the entire world has been estimated for 113,000 TWh for 2017 (IEA, 2019). The cheapest alternative to transport this hydrogen to the NSEC, will be by the existing natural gas grid from Northern-Africa to Northern-Europe. The expected production costs will be € 34-44 per MWh in 2050 (Gas for Climate, 2019).

2.6 Relevance to Industrial Ecology

This research is conducted by an Industrial Ecologist. In the field of Industrial Ecology, it is important to realize the core values of the field and to incorporate those in the conducted research.

The field of Industrial Ecology is founded on the concept that humanity should aim for maintaining sustainability, when considering the continued economical, technological and cultural evolution (Graedel & Allenby, 2010). This concept does not allow an industrial system to be perceived without taking its surrounding systems into account. The industrial system must be maintained in accordance with its surrounding systems. This is because, the industrial system is influenced by its surrounding systems. On the other hand, industrial systems can influence other surrounding systems as well, for example by the emission of greenhouse gasses.

In an idealized integrated industrial system, organizations and industries utilize each other's material and energy flows to reduce the required virgin materials and energy inputs and thereby the output of emissions from the entire system (Allenby, 2016). This can contribute to sustainable development. The transition towards a renewable energy system where fossil fuels are no longer a prerequisite for any economic activity, is a vital part of the foundation of Industrial Ecology. The energy transition enables to create an energy industry to become less dependent on the mining of raw materials and less polluting to its surrounding systems. On top of that, it also allows other industries to decrease their dependency on raw materials, fossil fuels and the resulting emission of greenhouse gasses.

3. Methodology

In order to investigate the drafted research questions, a methodology has been developed. This methodology is discussed in the following chapters. In order to investigate the research questions, an energy system model has been used. This model will be presented in Chapter 3.1. In Chapter 3.2, the research processes and the conducted analysis of the outputs of the model will be explained. Thereafter, a further elaboration on the model is presented as Chapter 3.3 presents the main components of the model and Chapter 3.4 describes the model of the assumptions made. In Chapter 3.5, the definition of all input data for the model are presented. Based on the defined research questions, scenarios of energy systems designs have been established. These scenarios include constraints to power generation capacities and the system design. An explanation of the drafted scenario is provided in Chapter 3.6.

3.1 Model introduction

As previously mentioned, this study is executed by optimizing the investment and operational costs of a future energy system in the modelling program Powerfys. This in-house model of Guidehouse (formerly known as Navigant / Ecofys) has been previously used for several energy system optimization problems. Powerfys can be considered as a unit commitment (UC) model. An UC model allows the optimization of the commission and decommission of power plants in order to meet the demand at minimum costs, while considering constraints of power plants and the energy system as a whole (Melhorn, Li, Carroll, & Flynn, 2016). The model used in this research is called Powerfys and the design and the optimization routine are based on a model described and developed by Abrell & Kunz (2014).

This model of Abrell & Kunz, called stELMOD, minimizes costs for power plants according to a rolling planning on two different energy markets, which also applies to the Powerfys model. The dispatch of power plants in both models is based on two energy markets. These two markets are the day-ahead market and the intra-day market. At the day-ahead market, bids are made before mid-day (12.00) for the following day. Because of fluctuations in real hourly generation of renewable energy sources, it occurs that there are differences between the submitted bids of energy generation and the real generation. The differences between the bids made at the day-ahead market and the real energy generation are traded at the intra-day market. The dispatch in both markets is considered for the following 36 hours. This process that has just been described is identical for the model of both Abrell & Kunz as well as Powerfys.

While the model of Abrell & Kunz was designed for the German energy market, Powerfys can be used for the simulation and optimization of energy system scenarios for multiple countries. Besides that, the model of Abrell & Kunz only considers time frames of 168 hours (1 week), while Powerfys has time frames of 8760 hours (1 year). This can be explained by the purpose of the model. The model of Abrell & Kunz aims to investigate the consequences of better forecasting of wind generation for the energy system, while Powerfys aims to optimize the entire energy system based on parameters from multiple types of power plants and infrastructural limitations.

Another important difference between both models is that the model of Abrell & Kunz presents a stochastic simulation model, while Powerfys can be considered as a model that optimizes according to a deterministic approach. The major difference between these two approaches is that the stochastic model defines parameters for uncertainty, while the deterministic model does not integrate that and considers all provided parameters for the model to be certain. In a stochastic model uncertainty will cause that energy sources with a certain availability rate possible show a deviating availability according to the provided uncertainty after simulation. As Powerfys is deterministic, the provided availability of energy sources is fixed and does not include the uncertainty of a stochastic simulation model.

Powerfys operates in a different manner than the real-world energy system. In the real-world energy system, individual energy providers attempt to maximize their profits by dispatching power plants. Individual energy providers in the real world do not know all information and dispatch strategies from their opponent's energy providers. This lack of knowledge from other parties in the same market is called imperfect information. Imperfect information of the different rival energy providers can lead to suboptimal use of the power plants. This is considered as a market inefficiency.

In Powerfys, the dispatch of all power plants in Powerfys are determined by a single algorithm that has complete and accurate information of all power plants. As the central algorithm has all information of all power plants, regardless of the potential different operators of the plant, it can be considered as perfect information. This availability of perfect information contributes to a higher market efficiency in Powerfys than what is considered as possible in the reality. Therefore, it can be stated that only if the real-world energy market would function as a market without imperfect information at all parties involved in the market, it would reach the same outcomes as the Powerfys model.

Besides the running of scenarios and determining the lowest energy system costs, Powerfys can also provide optimization for the deployment of additional capacity of power plants, transmission infrastructure and storage facilities. This means that the model allows to determine the optimal set of deployments in a given year, based on all provided parameters. By performing numerous iterations, the models seek to find the optimal set of deployment capacities given the limitations provided. These limitations consist of a minimum and a maximum capacity of deployment of a certain plant or infrastructure in or between a certain node in the model. The model performs iterations until the most optimal scenario is developed.

Powerfys has been designed for previous research done by Guidehouse. The conducted research with Powerfys related to the North Sea Wind Power Hub concerned only the electricity sector of the NSEC and the design choices to be made towards 2050. The inputs, design- and model assumptions made in this study have provided a starting point for the development of scenarios in this research.

3.2 Research process

This thesis has been written during an internship at Guidehouse. During the internship, data and tools have been provided by Guidehouse to support the realization of this research. The input data and the tools that have been used in this study are mentioned.

Based on the defined research question of this thesis, scenarios are developed. The starting scenario is based on previous research from Guidehouse on scenarios for the energy system of the NSWPH. From this starting point, further scenarios are developed in line with the research questions mentioned in Chapter 1.5. After the development of scenarios, input files are developed, of which the input data and the assumptions made align with the corresponding scenario. These input files are used as the input for the model runs executed in the optimization modelling program. This model provides the optimization of the energy system, based on previously designed model assumptions and restrictions. The model, called Powerfys, is developed in-house by Guidehouse and is further explained in Chapter 3.2. The runs are done in GAMS (General Algebraic Modeling Language), a modelling program to formulate complex optimization problems (GAMS, n.d.). The outputs provided as a result of these simulations are analyzed in MATLAB to generate interpretable results. These results provide the answers to the drafted research questions of this thesis. In Figure 8, an overview of the research processes can be viewed, including the main inputs & constraints of the scenarios and the generated outputs which are researched.

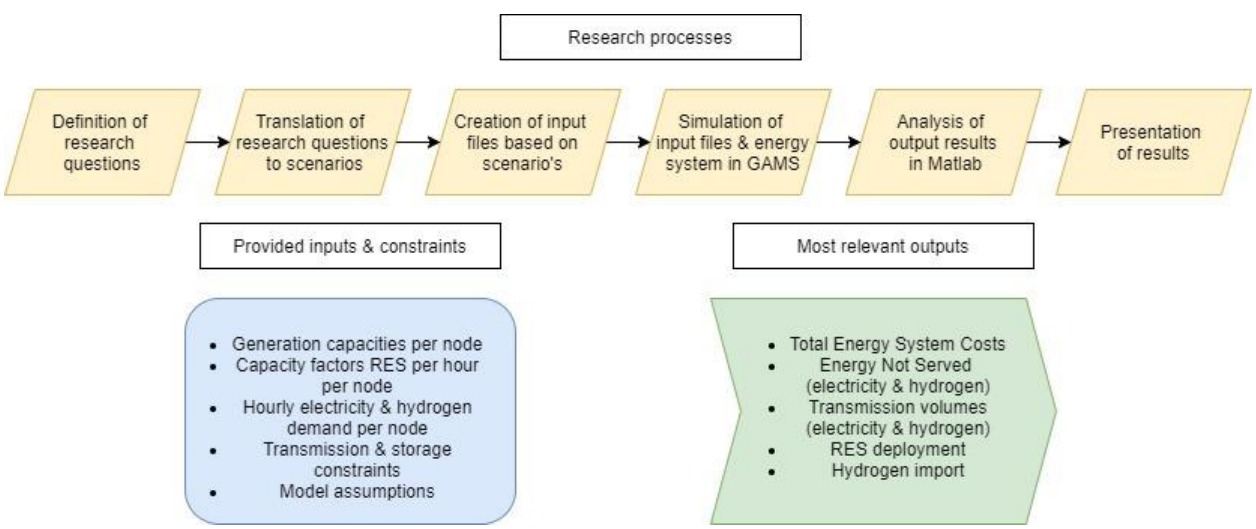

FIGURE 8 - OVERVIEW OF THE RESEARCH PROCESSES, THE PROVIDED INPUTS & CONSTRAINTS AND THE MOST RELEVANT OUTPUTS

3.3 Input parameters of the model

The design of Powerfys contains of many parameters, which allows the modelling of a complex energy system. The essential parameters of this model are addressed and further explained. Also, the design choices which are made for this research are clarified. This chapter only describes the design of the model, not the input data; this is discussed in Chapter 3.5. In Chapter 3.3.1, the general parameters, not related to energy, are described. Following in Chapter 3.3.2, the parameters related to energy are explained.

3.3.1 General components

To the general components of this energy system model, time and space can be considered. The elaboration of both elements in this model, is further explained.

<u>Time</u>

As this model is unit commitment model, it operates for a certain amount of time units in one or multiple years. In this study, Powerfys will simulate an energy system for one year only. This can be called a steady-state energy system. The time unit in Powerfys is hours and the model can consist of 8760 hours. In Powerfys, these hours can be related to different conditions in the model, such as the wind speeds or solar radiation in a given hour. This is relevant to the intermittent power plants of this research.

<u>Space</u>

Powerfys consists of a set of nodes. These nodes can represent regions on different geographic resolutions. The energy demand and production in this node is therefore accumulated, as a simplification of the reality. In this research, the nodes represent different regions in a certain country of the NSEC. The nodes for this model are based on a set of nodes attributed to regions by the e-Highway 2050 study (e-Highway2050, 2015).

The countries the Netherlands, Belgium, Luxembourg and Ireland consist of only one node. The countries Germany, France, the United Kingdom, Denmark, Sweden and Norway consist of multiple nodes. This can be motivated by the large differences in supply and demand among these nodes in these countries. Therefore, it justifies the splitting of these countries over multiple nodes. A visual representation of all nodes can be found in Figure 9. For an exact description of the regions per node, see Appendix A. In the developed model for this research only the nodes of the NSEC are represented in the model. As shown in Figure 9, also 6 nodes are located offshore in the North Sea. The distance between all nodes is different. This distance between nodes is decided by estimating the distance between central locations in every node. The distance between all different nodes is shown in Appendix F. As only the nodes of the NSEC are considered in this model, these 10 countries can be considered as an island which is isolated from surrounding countries.

In reality, there are different interconnections of several NSEC countries with neighboring countries that are not part of NSEC (and this model). As some interconnections are considered as vital for several regions, some concessions have been made by compensating the lack of interconnectivity with the addition of extra energy storage possibilities in the neighboring region in NSEC. This is mentioned in Chapter 3.5.3. Also, the limitations of the isolation of the NSEC countries from neighboring countries outside NSEC and the possible effect on the outcomes of this research is touched upon in the discussion of Chapter 6.

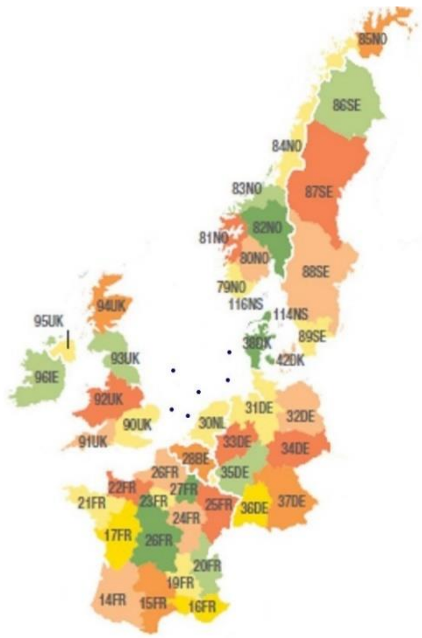

***FIGURE 9 - VISUALIZATION OF THE NODES NSEC, WHERE OFFSHORE NODES ARE MARKED AS DOTS, BASED ON E-HIGHWAY* (E-HIGHWAY2050, 2015)**

3.3.2 Energy-related components

Besides the general components, the energy system model consists of multiple energy-related components. The essential components for this study are power plants, storage units, transmission and conversion plants. For all of these components, it is possible to determine an existing capacity of this component in the model in a node or between nodes. In addition to that, the model allows to expand this existing capacity within a bandwidth (with a minimum and maximum of new capacity) that it determined. In accordance with these given constraints, the model optimizes if existing capacities are sufficient or require to be expanded.

Energy demand
The optimization of the modelled infrastructure is based on meeting the demand of both electricity and hydrogen in a certain area. This demand is specified in the hourly demand of electricity or hydrogen for a specific node. The demand can fluctuate over the course of days, weeks or months. The behavior of demand over the course of time in a node is called the load profile. Which data was used for determining the load profile for each node is explained in Chapter 3.5.1.

Power plants
In Powerfys, generation plants are defined to generate the energy demanded by the different nodes. In the model, the capacity of generation of a certain type of powerplant can be determined on beforehand, but it can also be flexible according to the optimization of the energy system by Powerfys. The capacity constraints per power plant per node can be entered in the model as:

3. Old Capacity: The existing generation capacity of a certain power plant in a node
4. Added Potential: the maximum of extra generation capacity that can be deployed in a node.

This means that the generation capacity of a power plant in a node results in an amount in between the Old Capacity and the sum of the Old Capacity and the Added Potential.

Powerfys allows power plants to be constrained by must-run levels, start-up or shut-down costs, on- and off times and curtailment. Must-run levels consider the minimum generation level at which a power plant needs to operate in order to operate. This is usually expressed in a percentage of the total generation capacity. This constraint is only applicable to conventional power plants. The must-run levels for this model are shown in Chapter 3.5.2. Start-up and shut-down costs refer to the costs related to those two activities. On- and off times of power plants concerns the minimum of being operating or being idle in order to function properly. Curtailment refers to the amount of energy curtailed by power plants during operation and it is only applicable to renewable generation plants.

In this model, three categories of power plants can be distinguished; conventional power plants, renewable generation plans and so-called import plants. All power plants have costs related to capital expenditures (CAPEX) and operational expenditures (OPEX) that are determined per power plant. Each of these categories have different properties and will therefore be addressed separately.

Conventional power plants
This type of power plants concerns power plants operating on fuels, either fossil or biological. Therefore, these plants do not only have a defined CAPEX and OPEX, but also a fuel cost. On top of that, costs related to the starting up and the ramping up of the power plants are considered in Powerfys. Conventional power plants require a minimum generation level at all time. From this minimum generation level to the maximum generation level, the plant can

produce an amount of power in accordance with the demand. This means that the generation level of the plant can be considered as load-following.

In Powerfys, the following conventional power plants are incorporated: nuclear power plants, coal-fired power plants (with CCS), gas-fired power plants (with CCS) and biomass-fired power plants.

Renewable power plants
Renewable power plants are running on abundant resources and do not require any fuel. Therefore, no fuel costs are associated with these type of power plants. What distinguishes renewable power plants from conventional power plants is that their maximum generation level relies on the availability of the required energy source, such as wind, solar or the run of water. Therefore, the capacity factor of a certain renewable power plant differs per hour and per node in Powerfys. The availability per source is determined by the capacity factor of every type of power plants for a specific region during a specific hour. Thus, renewable power plants cannot be considered as load-following power plants. Yet, renewable power plants are able to produce less than the maximum generation level at that moment. This is due to curtailment. Powerfys allows the curtailment of the renewable power plants incorporated in this model.

In Powerfys, the following renewable power plants are incorporated: PV (solar energy), wind energy onshore, wind energy offshore, and hydro energy.

Import plants
As the model design considers the nodes of NSEC altogether as an island, no interaction of transmission of electricity or hydrogen takes place. To allow the imports of hydrogen from countries outside the NSEC, so-called hydrogen import plants are deployed in the model. These hydrogen import plants are meant to facilitate the import of hydrogen by transmission pipelines from the Sahara to Northern-Europe, as discussed in Chapter 2.3.4. Therefore, they can be considered as artefacts to model import in Powerfys. These plants operate in a different manner than the above-mentioned power plants. The artificial plant does not require any fuel and does not have any minimum generation levels that are required. Yet, the demand of hydrogen import can be between 0 and 100% of the deployed size of the deployed power plant.

	Conventional plants	Renewable plants	H2 import plants
Fuel required	Yes	No	No
Load-following availability	Yes	No	Yes
Output generated	Electricity	Electricity	Hydrogen
Minimal must-run required	Yes	No	No

TABLE 1 - MAIN DIFFERENCES IN CHARACTERISTICS BETWEEN POWER PLANTS

Storage

In order to store electricity and hydrogen for meeting later demands, storage units are designed in the model. For electricity storage, two different storage technologies are integrated, while for hydrogen storage one storage technology is integrated.

The electricity storage can be distinguished in battery storage units and pumped-hydro storage units. Battery storage is a suitable technology for short-term storage, i.e. several hours. Pumped-hydro storage units allows for electricity storage on a more longer-term. Nevertheless, the availability of this technology is limited due to geophysical requirements.

For hydrogen storage, salt caverns are integrated in the model as a storage technology for the long term.

Transmission

The energy flows between different nodes in the model constitute via transmission infrastructure. This transmission infrastructure allows for the distribution of either electricity or hydrogen among different nodes. The nodes connected by transmission infrastructure forms a grid. This grid shows which nodes are connected with each other. In this model, two infrastructural transmission grids are developed. One grid is used for transmission of electricity, while the other grid is used for transmission of hydrogen.

Conversion plants

This model studies both electricity and hydrogen. As those technologies are complementary, electricity can be converted in hydrogen and vice versa. For the conversion from electricity to hydrogen, Power-to-Gas (P2G) plants are deployed. When hydrogen is converted in electricity, Gas-to-Power (G2P) plants are required. These G2P plants are in this research distinguished by two different type of plants: Open-Cycle Gas Turbine (OCGT) and Closed-Cycle Gas Turbine (CCGT).

3.4 Model limitations

For the design of the Powerfys model and the development of scenarios related to this research, several assumptions or limitations are determined to enable the modelling of the energy system for the NSEC in 2050. The most essential of these are mentioned and further elaborated.

Only interactions between countries of the NSEC are incorporated in the model. For reasons of simplification, it is chosen to not consider interactions of energy transmissions with countries outside the NSEC. Therefore, the country borders of the NSEC altogether can be considered as the system boundaries of the model. The only example to this is the import of hydrogen, which is enabled by the presence of H2 import plants. This is explained in Chapter 3.2.2.

All flows of electricity and hydrogen within country border are unconstrained. Due to lack of data regarding the gas transmission infrastructure within country borders of several countries in the NSEC, it is chosen to not consider infrastructural constraints within national borders. In order to create a level playing field for both energy carriers, also the electricity transmission infrastructure within national borders is considered to be unconstrained. Therefore, this research only researches the optimization of transmission infrastructure development on a cross-border level.

The model considers a steady-state scenario of the energy system in 2050. For this research, only the energy system of a single year, being 2050, is modeled and simulated. The consequence of this is that pathways of previous decades and lifetimes of power plants and infrastructure are neglected in the energy system optimization of the model.

All parameters taken as input for the model are projections for the year 2050. As this research focusses on the development of energy infrastructure in 30 years from now, all inputs are based on studies that project developments in 30 years. Because of this large timespan and the rapid pace of development in the energy sector, there is a large margin of uncertainty. The smaller the amount of time between now and the projected year, the smaller this margin of error is.

All electricity generated in the model is carbon neutral.
In line with the previous studies on the NSWPH by Guidehouse and the current policies on decarbonization of the electricity sector, it is assumed that the entire energy generation is done without the emission of CO_2 in 2050. Therefore, the model only allows the deployment of conventional power plants when this also incorporates CCS technology. The costs for CCS technology are therefore included in the costs of each fossil-fueled power plant.

3.5 Definition of input data & design assumptions

All input data of the model are projected parameters for the year 2050. These projected parameters are deduced from different data sources. The input data used for the modelling in this research is discussed per energy-related component that has been mentioned in Chapter 3.2 of this research. Per component, the data sources are mentioned, and necessary assumptions made are explained.

3.5.1 Energy demand

The energy demand load for electricity and hydrogen is determined in two different methods. Each method is explained separately.

For the electricity demand, the total electricity demand in the 1.5TECH scenario (1.5 TECH Scenario - EC, 2018) was used as the starting point. The allocation of electricity demand over the countries considered in NSEC has been based on the TYNDP2018 (2018) study. From the annual national electricity demand, the hourly demand per node had to be defined. Again, the TYNDP2018 study was consulted to determine the hourly load profiles of the electricity demand per node.

For the determination of the hydrogen demand, a recent study from Guidehouse commissioned by a consortium of gas TSO's in Europe has been consulted (Gas for Climate, 2020). In this study, a total hydrogen demand of 627 TWh for the industrial sector and 252 TWh for the mobility sector for the EU has been projected for 2050. The expected hydrogen demand for the buildings sector is considered as far less significant compared to the industrial and mobility sector and therefore left out of the research for the sake of simplicity (Gas for Climate, 2020). The reason why the hydrogen demand for 2050 mentioned in 1.5TECH has not been chosen as starting point, is because the scenario did not provide a substantiation of the hydrogen demand per sector and therefore made it difficult to allocate the total hydrogen demand over countries and over nodes.

As the mentioned numbers only provide a European hydrogen demand for 2050, a distribution to node-level had to be made. For this, economic indicators have been used to first allocate hydrogen demand to the countries of NSEC. After this allocation, the NSEC has a total hydrogen demand of 417 TWh for the industrial sector and 113 TWh for the mobility sector in 2050. Following on that, an allocation of the national hydrogen demand for countries with multiple nodes over these nodes had to be made. Again, economic indicators have been used to distribute to the national hydrogen demands to nodes. The indicators chosen are related to the major hydrogen demanding sub-sectors in the mobility and industry sector. For the industrial sector, this meant that most indicators have been related to heavy industry, while for the mobility sector the indicators are closely related to freight-transport and trucks. According to the Gas for Climate study, these two subsectors are the main drivers of hydrogen demand in 2050. The exact overview of all used indicators for allocation of hydrogen demand are shown in Appendix B.
An overview of the electricity and hydrogen demand per country in the year 2050 is shown in Table 2, shown below.

Country	Annual electricity demand (TWh)	Annual hydrogen demand (TWh)
Belgium	100.9	19.6
The Netherlands	147.6	27.1
France	501.8	82.5
Germany	654.9	211.9
Luxembourg	9.3	1.9
Denmark	60.3	12.1
Norway	145.7	25.3
Sweden	164.0	24.1
United Kingdom	371.8	99.6
Ireland	45.1	25.4

TABLE 2 - OVERVIEW OF ANNUAL ELECTRICITY AND HYDROGEN DEMAND PER COUNTRY **(1.5 TECH SCENARIO - EC, 2018) (TYNDP2018 EXECUTIVE REPORT, 2018)**

3.5.2 Power plants

For all conventional and renewable power plant deployment capacities for 2050 in the NSEC, the 1.5TECH scenario (2018) was consulted. The division of capacities per country is based on the TYNDP2018 Executive Report (2018). Finally, the division of capacities per node is conducted by Guidehouse. Also, the technical and economic parameters of all power plants are based on internal data from Guidehouse. The inputs imply a full coal phase-out in 2050 and only allow gas-fired power plants that are operating with CCS. This means that a net zero emission of electricity supply is implied. The technical parameters of all power plants are shown in Table 3. All economic parameters used for this study can be found in Table 3.

Power plant	η / efficiency (in % of total)	Lifetime (in years)	Min gen (% of total)	Max gen (% of total)
Nuclear	30%	30	60%	100%
Gas with CCS	51%	30	40%	100%
Biomass	33%	30	40%	100%
P2G	75%	25	0%	100%
OCGT for H2	37%	25	20%	100%
CCGT for H2	61.5%	25	40%	100%
Offshore wind	100%	30	-	-
Onshore wind	100%	30	-	-
PV	100%	30	-	-
Hydropower	100%	50	-	-
H2 import	100%	50	0%	100%

TABLE 3 – TECHNICAL PARAMETERS OF ALL POWER AND CONVERSION PLANTS **(GUIDEHOUSE, 2020)**

Previous studies performed by Guidehouse on the energy system of the NSEC, only considered the electricity system. For that reason, a fraction of 50% of the installation capacities for the RES determined in 1.5TECH has been deployed in these scenarios. Powerfys allows to define a fixed capacity to be deployed and an added capacity of addition deployment. As this research will not only serve the electricity demand, but also the hydrogen demand, an increase in RES capacity deployment onshore is allowed up to 75% of the numbers in 1.5TECH. The reason that not 100% of 1.5TECH is chosen (or a percentage between 75% and 100%) is because the energy demand for some sectors is yet incorporated. Examples of not considered sectors are the aviation and shipping industry, where synthetic fuels are expected to be vital.

It is chosen to make the 50% a fixed capacity, while the 25% additional capacity is added as added potential. In this way, the models are allowed to deploy the capacity per node (between 50% and 75% of the 1.5TECH capacities) that leads to the most cost-efficient outcome of the scenario. In which scenario the addition deployment will be enabled is explained in Chapter 3.6.

Power plant	Investment costs (€ / MW)	Fix OPEX (annual % of investment costs)	Fuel prices (€ / MWth)	Start-up costs incl. fuel (€ / MW)	Ramping costs (€ / MW)	WACC (%)
Nuclear	4950	3.68	0.0017	0.0276	0.0026	0.05
Gas with CCS	2915	3.02	0.0306	0.1076	0.002	0.05
Biomass	2475	3.56	0.0296	0.1980	0.0026	0.05
P2G	667	3.00	-	-	-	0.05
OCGT for H2	450	3.00	-	0.0200	0.0014	0.05
CCGT for H2	800	3.13	-	0.2500	0.0016	0.05
Offshore wind	1560	2.74	-	-	-	0.05
Onshore wind	1195	2.01	-	-	-	0.05
PV	560	1.96	-	-	-	0.05
Hydropower	2915	2.64	-	-	-	0.05
H2 import	1100	5.00	0.0880	0.0000	0.0000	0.05

TABLE 4 - ECONOMIC PARAMETERS OF ALL POWER AND CONVERSION PLANTS **(GUIDEHOUSE, 2020)**

For offshore wind, another study has been examined to determine the potential generation of offshore wind turbines in the North Sea. A study commissioned by WindEurope (2019), previously mentioned in Chapter 1.2, found a significant larger potential of offshore wind deployment for the North Sea (336.6 GW) than the 1.5TECH scenario (183.6 GW). Main differences between both studies are the higher deployment capacities by WindEurope in the far offshore regions on the North Sea and Norway and Sweden. The most obvious reason for this is that the 1.5TECH scenario has not considered the large potential of floating offshore wind turbines, which enables deep waters in the Nordics and far offshore sites in the North Sea to be eligible for wind farm development. As the potential estimated by the WindEurope study (WindEurope, 2020) might not be (fully) required for the energy system of 2050, the difference between the 1.5TECH and WindEurope study is inputted in the model as extra deployment potential.

The capacities of renewable power plants per country are shown in Table 5. In Appendix D, the capacities for all power plants per node can be found.

Node	**PV**		**Onshore wind**		**Offshore wind**		**Hydropower**
	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)
France	51551	25775	53582	26791	29272	11228	22934
Belgium	19487	9744	8462	4231	12148	0	322
Luxembourg	951	476	275	137	0	0	148
The Netherlands	40747	20373	8132	4066	10879	0	18
Germany	124896	62448	89621	44811	29048	0	4166
Denmark	6602	3301	7890	3945	2285	2610	4
Norway	3001	1500	10036	5018	400	36600	41424
Sweden	5937	2969	19142	9571	1908	17892	18455
United Kingdom	34547	17273	21896	10936	19218	4598	3360
Ireland	1772	886	7143	3572	3220	18980	171
Offshore	0	0	0	0	29136	60488	0

TABLE 5 - CAPACITIES OF ALL RENEWABLE POWER PLANTS PER COUNTRY IN MW

As mentioned in Chapter 3.3.2, the import of hydrogen is enabled in the model by creating hydrogen import plants. These artefacts of hydrogen import plants, that do not require any other fuel than hydrogen and do not have a minimum generation level, in contrast to conventional power plants. All related parameters for the hydrogen import plant can be found in Table 3 and 4. These parameters are based on numbers published in Gas for Climate (2020) and are then converted to parameters suitable for the created hydrogen import plant. The location of hydrogen import power plants has been based on the geographical sighting of each node. It has been chosen to allow hydrogen import plants at all nodes located on the southern borders of the NSEC, as this would be the logical location to import hydrogen from the Sahara from, and in the coastal located nodes of each country. This is because hydrogen can be imported via either ships, arriving in ports, or pipelines that land on shore in coastal nodes. An overview of the chosen nodes with hydrogen import plants is shown in Table 6.

Nodes in south of NSEC	14_FR, 15_FR, 34_DE, 36_DE & 37_DE
Coastal nodes in NSEC	17_FR, 21_FR, 22_FR, 26_FR, 28_BE, 30_NL, 31_DE, 32_DE, 38_DK, 72_DK, 79_NO, 81_NO, 88_SE, 89_SE, 90_UK, 91_UK, 92_UK, 93_UK, 94_UK, 95_UK & 96_IE

TABLE 6 - NODES WITH HYDROGEN IMPORT PLANTS

3.5.3 Storage

For determining the capacities of battery storage and pumped-hydro storage installations per node the 1.5TECH scenario (2018) has been consulted. The division for capacities per country is based on the TYNDP2018 Executive Report (2018). Finally, the division of capacities per node is conducted by Guidehouse. The technical and economic parameters have been based on internal data from Guidehouse. The details of these parameters can be found in Table 7 and Table 8.

Storage plant	η / round-trip efficiency (in % of total)	C-rate (MWh/MW)	Lifetime
Battery_4	96%	4	20
Battery_2	90%	2	20
Battery_6	90%	6	20
H2 salt caverns	98%	50	50
Pump	80%	8	50
Pump67	90%	67	50
Pump190	90%	190	50

TABLE 7 - TECHNICAL PARAMETERS OF ALL STORAGE PLANTS **(GUIDEHOUSE, 2020)**

Storage plant	Investment costs (€ / MW)	Fix OPEX (annual % of investment costs)	WACC (%)
Battery_4	460	3.96	0.05
Battery_2	311	5.21	0.05
Battery_6	621	3.27	0.05
H2 salt caverns	67.2	2.00	0.05
Pump	1000	2.00	0.05
Pump67	1000	2.00	0.05
Pump190	1000	2.00	0.05

TABLE 8 - ECONOMIC PARAMETERS OF ALL STORAGE PLANTS **(GUIDEHOUSE, 2020)**

As shown in the above table, three different technologies have been modelled in Powerfys for both the battery storage facilities and for the pumped-hydro storage facilities. The reason that three different battery storage technologies are chosen is because of the different C-rates of these batteries. These C-rates are mentioned in Table 7. These different capacities make them suitable for different business cases. The C-rate is the factor of dividing the charging/discharging power to the battery capacity. Batteries with a low C-rate have a relatively low capacity compared to the charging/discharging power. They also have a relatively low investment cost and are therefore more suitable for short-term electricity storage. Batteries with a higher C-rate have a relatively high capacity compared to the charging/discharging power. Therefore, the are more applicable for storage in the somewhat mid-long term. For the pumped-hydro storage facilities are different technologies chosen because of the same reason as for the battery-storage facilities and because of the suitability of a certain technology at a geographical location. Not all three technologies are suitable to be deployed in any geographical area. Therefore, this distinguishment has been made.

For the estimations of hydrogen storage capacities in salt caverns the research mentioned in Chapter 2.3.3 is consulted (Caglayan, et al., 2020). The allocation of storage capacity per node is done by estimations based on the availability of eligible salt caverns in different regions. For the sake of simplicity, the national potential capacity has been divided equally over the regions with eligible salt caverns. The availability of eligible salt caverns in Europe is shown in Figure 10. From the technical potential per node that is estimated by this research, 20% is considered as economically viable. From this 20%, only 70% has been inputted in the model as hydrogen storage capacity, as approximately 30% of the storage capacity has to be reserved for cushion gas. This cushion gas is required in order to maintain adequate pressure in the salt cavern.

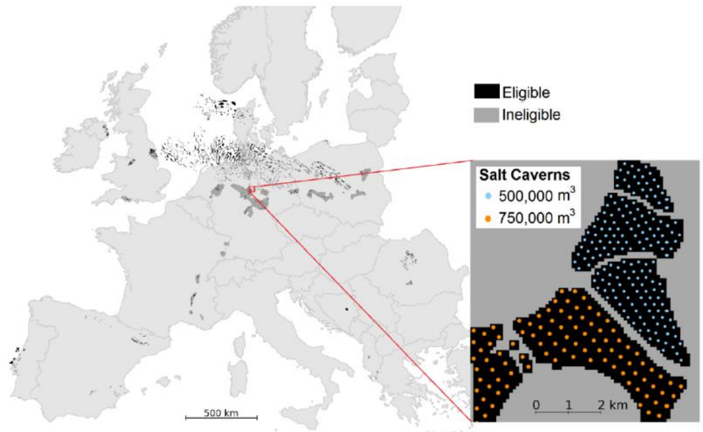

FIGURE 10 - OVERVIEW OF ELIGIBLE AND INELIGIBLE SALT CAVERNS IN EUROPE (CAGLAYAN, ET AL., 2020)

As mentioned in Chapter 3.3.1, the absence of interconnections of NSEC countries with neighboring countries outside NSEC has been partially compensated by adding additional energy storage in some regions. This has only been the case for Southern-Germany. This region is expected to be depended on pumped hydro storage facilities in the Alps of Switzerland and Austria. Therefore, some of the hydro storage facilities that are expected to be operational in 2050 in Switzerland and Austria close to the border with Germany has been added to the available storage facilities in South Germany.

Node	Battery_2		Battery_4		Battery_6	
	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)
France	0	1000000	9130	0	0	1000000
Belgium	0	1000000	1793	0	0	1000000
Luxembourg	0	1000000	162	0	0	1000000
The Netherlands	0	1000000	2678	0	0	1000000
Germany	0	1000000	11307	0	0	1000000
Denmark	0	1000000	1050	0	0	1000000
Norway	0	1000000	2524	0	0	1000000
Sweden	0	1000000	2835	0	0	1000000
United Kingdom	0	1000000	6889	0	0	1000000
Ireland	0	1000000	798	0	0	1000000
Offshore	0	0	0	0	0	60488

TABLE 9 – CAPACITIES OF ALL BATTERY STORAGE PLANTS PER COUNTRY IN MW

Node	Pump		Pump_67		Pump_190		H2 Salt caverns
	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Added Potential (MW)
France	78	0	8409	0	1400	0	0
Belgium	0	0	1308	0	0	0	0
Luxembourg	0	0	1044	0	0	0	0
The Netherlands	0	0	0	0	0	0	336000
Germany	0	0	8094	0	7622	0	12600000
Denmark	0	0	0	0	0	0	1820000
Norway	0	0	10936	0	0	0	0
Sweden	0	0	0	0	0	0	0
United Kingdom	0	0	4046	0	0	0	3360000
Ireland	0	0	1206	0	0	0	0
Offshore	0	0	0	0	0	0	0

TABLE 10 – CAPACITIES OF ALL PUMPED HYDRO & HYDROGEN STORAGE PER COUNTRY IN MW

The capacities of storage plants per country can be found in Table 9 and 10. The capacities for storage per node are shown in Appendix E. For the capacities of battery storage, this study offers a fixed capacity per node for the Battery_4. Besides that, it allows the model to expand battery storage capacity for every node almost unlimitedly by either a Battery_2 for short-term storage or Battery_6 for mid-term storage. For the hydrogen storage in salt caverns it is chosen to not assume any installed capacity for 2050 in the NSEC. Instead, it is chosen to let the model determine the required storage capacities based on the model optimalizations. The limits to these hydrogen storage capacities are set by the amount of the Added Potential capacities per node. As shown in Table 10, hydrogen storage is only available in Germany, The Netherlands, Denmark and The United Kingdom. Regarding pumped hydro storage, it is chosen to only insert fixed capacities per node. This is because the availability of pumped hydro storage is geographically limited to certain countries.

3.5.5 Transmission

For the transmission grid of electricity, data has been retrieved from the e-Highway2050 study (e-Highway2050, 2015) and a deliverable of this study (Pestana, 2015). This study provides transmission capacities of electricity for both 2030 and 2050. From this study, the 2030 grid outlook has been taken as the starting point. The 2050 grid outlook is used as additional expansion capacity in some of the scenarios in this study.

For the transmission grid of hydrogen, this research assumes that the planned natural gas grid for 2040 by ENTSOG is retrofitted and fully utilized for the transmission of hydrogen in 2050 (ENTSOG, 2019). Besides this infrastructure, no additional transmission infrastructure for hydrogen is assumed. This is for the reason that there are currently no dedicated hydrogen transmission pipelines built or planned on which the design of this model could rely. The only existing hydrogen infrastructure is in private ownership and any transmission capacities of this infrastructure is not publicly disclosed.

The planned transmission grid data has been retrieved from a map of current cross-border transmission capacities of the natural gas grid by ENTSO-G and by the planned developments of the natural gas grids toward 2040 (ENTSOG, 2019) (ENTSOG TYNDP, 2019). As 2040 is the furthest year of which data projections can be found, the data projections for this year are taken as input for this study. The map is shown in Figure 11. These sources only provide the transmission capacities of the cross-border infrastructure in Europe. For the transmission capacities of infrastructure within national borders, no data has been found.

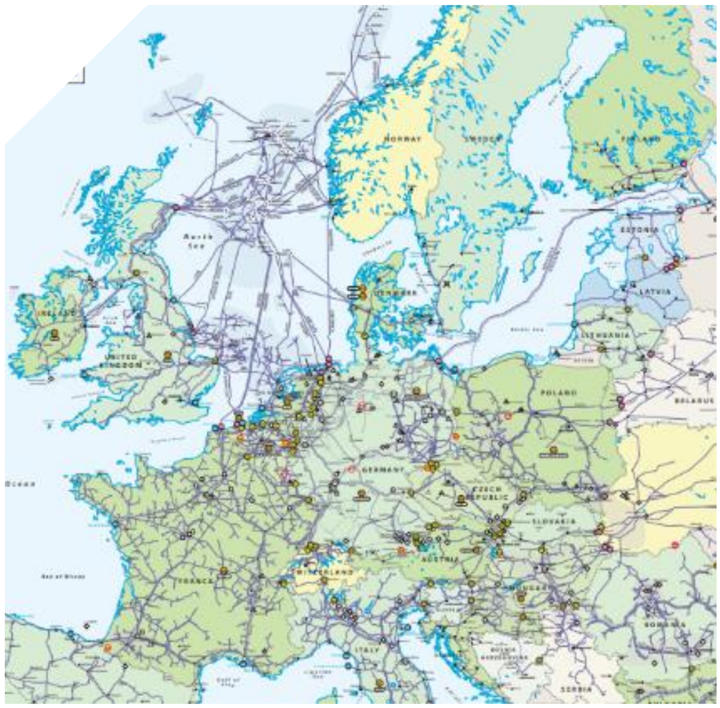

FIGURE 11 - EUROPEAN TRANSMISSION GRID OF NATURAL GAS (ENTSOG, 2019)

Because of the lack of data of transmissions capacities of the natural gas infrastructure within national borders, transmission capacities between nodes in a single country could not be determined. For this reason, it is assumed that all hydrogen transmission flows between nodes within national borders are unconstrained. This means that constraints in transmission capacities only appear between nodes between different countries. In order to create a level playing field between electricity and hydrogen transmission infrastructure, the electricity transmission flows between nodes within national borders are designed to be unconstrained as well. Thus, this means that a copper-plate energy system can be assumed within the national borders of each country. On the other hand, congestion on the transmission infrastructure between countries (international transmission infrastructure) can still occur, as those are constrained by the data that has been obtained from above mentioned sources. All transmission values used for both electricity and hydrogen can be found in Appendix F.

3.5.6 Conversion plants

For the conversion plants, P2G and G2P, deployment capacities for 2050 are based on 1.5TECH (2018) . For the parameters of the conversion plants, internal data form Guidehouse is used. The technical and economic parameters of those plants are presented in Table 3 and Table 4. In the model design, it is chosen that P2G installations will only occur on onshore nodes. Recent studies are exploring the potential of P2G on offshore locations, but this can be considered as still early-stage (RVO, n.d.).

3.6 Description of scenarios

For finding the outcomes of the described research questions, different scenarios have been developed to model an energy system. The different scenarios are developed with different system constraints. These different constraints align with the stated research questions. The goal of these scenarios is to find out what system design choices contribute to the realization of a cost-efficient energy system in the NSEC for 2050. First of all, the starting scenario is presented. This starting scenario forms the basis for all other scenarios. After that, subscenarios are designed which add additional constraints to the previous scenario.

The starting scenario is Scenario 0 (S0). This scenario can be seen as the starting point from the simulations. This if followed by Scenario 1.1 and Scenario 1.2, which both have one subscenario. These scenarios are followed by Scenario 2.0 (S2) and certain subscenarios. All scenarios are based on research questions that are mentioned in Chapter 1.5. Figure 12 shows the sequence and the properties of each scenario, including the most important data per scenario.

For all scenarios, the first aim per scenario is to identify the energy self-sufficiency in the NSEC. This is determined by the parameter Energy Not Served. This number is a percentage of the total annual energy demand that could not be met over the course of the year. For both the electricity demand and the hydrogen demand, a percentage is distinguished.

When full self-sufficiency of the NSEC is shown, the main parameters to be analyzed becomes the total energy system costs. The different system design choices made in the subscenarios could lead to different optimizations of the energy system for the NSEC and thereby lead to a reduction in total energy system costs. In order to further interpret the output results of all scenarios, also other parameters are reviewed.

Scenario outline										Scenario data										
Scenario	Description	Offshore wind expansion	Onshore RE expansion	Hydrogen imports	Expansion of transmission infrastructure		P2G installations locations (nodes)			Offshore wind		Onshore wind		PV		Total cross-border electricity transmission		Total cross-border hydrogen transmission		Nodes with P2G
					Electricity	Hydrogen	Coastal	Inland	Offshore	Old Capacity (MW)	Max Potential (MW)	Old Capacity (MW)	Max Potential (MW)	Old Capacity (MW)	Max Potential (MW)	Old Capacity (MW)	Max Potential (MW)	Old Capacity (MW)	Max Potential	
S_0	Base-case	X	X	X	X	X	✓	X	X	139799	0	226474	0	291087	0	52030	0	58556	0	18
$S_{1.1}$	Additional offshore wind	✓	X	X	X	X	✓	X	X	139799	152396	226474	0	291087	0	52030	0	58556	0	25
$S_{1.1.1}$	+ hydrogen imports	✓	X	✓	X	X	✓	X	X	139799	152396	226474	0	291087	0	52030	0	58556	0	25
$S_{1.2}$	Additional onshore renewables	✓	✓	X	X	X	✓	X	X	139799	152396	226474	113239	291087	145543	52030	0	58556	0	25
$S_{1.2.1}$	+ hydrogen imports	✓	✓	✓	X	X	✓	X	X	139799	152396	226474	113239	291087	145543	52030	0	58556	0	25
S_2	Optimization electricity grid	✓	✓	✓	✓	X	✓	X	X	139799	152396	226474	113239	291087	145543	52030	129834	58556	0	25
$S_{2.1}$	Optimization P2G inland locations	✓	✓	✓	✓	X	✓	✓	X	139799	152396	226474	113239	291087	145543	52030	129834	58556	0	44
$S_{2.2}$	Optimization P2G at coast and offshore	✓	✓	✓	✓	X	✓	X	✓	139799	152396	226474	113239	291087	145543	52030	129834	58556	0	31
$S_{2.3}$	Optimization hydrogen grid	✓	✓	✓	✓	✓	✓	X	X	139799	152396	226474	113239	291087	145543	52030	129834	58556	∞	25
$S_{2.4}$	Optimization of 2.1 & 2.3	✓	✓	✓	✓	✓	✓	✓	X	139799	152396	226474	113239	291087	145543	52030	129834	58556	∞	44

FIGURE 12 - OVERVIEW OF MODEL SCENARIOS WITH THE GENERAL DATA

Scenario 0

Scenario 0 is the base-case scenario of this research. It is a pre-determined scenario which is derived from previous research conducted by Guidehouse (Scenario 3.1 in (Navigant, 2020)). This scenario is an optimized scenario for the NSWPH with low system costs and without any electricity deficits at any given time. Nevertheless, this scenario provides the optimal solution for the energy system when only considering the electricity system. As this research also integrates the hydrogen energy system, it can be expected that this scenario no longer provides the optimal scenario for the energy system of 2050. In this scenario, the generation capacities of all power plants are considered at 50% of the total generation capacities of the 1.5TECH scenario. Another aspect of this scenario is that no import of hydrogen from outside the NSEC is allowed. The aim of this scenario is to see to what extent the electricity and hydrogen demand can be met.

Scenario 1.1

This scenario is based on the first sub research question mentioned in Chapter 1.5: *How can a large-scale deployment of offshore wind and onshore renewables in the North Sea contribute to a cost-efficient energy system in the NSEC?*. Scenario 1.1 allows only the extra deployment of offshore wind in the North Sea, in accordance with the study of WindEurope (2019). This extra generation capacity of offshore wind is allowed in the model as Added Potential. This means that it will only be deployed in case this is required by the model to contribute to the most optimized design of the energy system in the NSEC. Just as Scenario 0, this model does not allow the imports of hydrogen from outside the NSEC. By allowing the model to deploy a higher amount of offshore wind generation capacity, it is expected that the ENS for this scenario will be 0%.

Scenario 1.1.1

This subscenario follows on Scenario 1.1 and is based on sub research question 2: *How can the import of hydrogen from outside NSEC contribute to a cost-efficient energy system in the NSEC?*. For this scenario, the import of hydrogen for the NSEC is allowed. This means that all demand that could previously not be, can now be met by the import of hydrogen. The import of hydrogen allows directly the ENS of hydrogen to become zero and could also eliminate the ENS of electricity by converting imported hydrogen to electricity. Therefore, a further cost-optimization of the energy system is expected in this subscenario.

Scenario 1.2

Besides the extra deployment of offshore wind in the North Sea compared to Scenario 1.1, this scenario allows the extra generation of onshore renewable. This scenario is based on the same sub research question as Scenario 1.1. The scenario allows the additional deployment of an extra 25% of the capacities mentioned in 1.5TECH for onshore wind and PV. The 25% of extra generation capacity of onshore wind and PV is inputted in the model as Added Potential. The reason that this Added Potential is allowed is because this study does not only consider the electricity demand (as in Scenario 0), but also the hydrogen demand in NSEC. Because this still does not cover the entire potential energy demand of NSEC in 2050, not the entire 100%

is allowed to be deployed. This is explained in Chapter 3.5.2. Added Potential means that the renewable technology will only be deployed in case this is required to contribute to the most optimized design of the energy system in the NSEC. This is in contrast to the 50% of capacity deployed from Scenario 0, as this capacity is fixed. Just as Scenario 0 and 1.1, this model does not allow the imports of hydrogen from outside the NSEC. As the model is allowed to deploy a more onshore renewable generation capacity, it is expected that the energy system costs are lower than in Scenario 1.1.

Scenario 1.2.1

This subscenario follows on Scenario 1.2 and is based on the same sub research question as Scenario 1.1.1. For this scenario, the import of hydrogen for the NSEC is allowed. This means that the model is able to perform a further model optimalization by supplying imported hydrogen when this contributes to a more cost-efficient energy system design for the NSEC. Therefore, a further cost-optimization of the energy system is expected in this subscenario compared to all previous scenarios.

Scenario 2

Starting from Scenario 2, expansion of transmission infrastructure is allowed. This scenario has been drafted to answer, partially, sub research question 3: *How can the expansion of the electricity grid or hydrogen grid contribute to a cost-efficient energy system in the NSEC?*. For this base case scenario, transmission of electricity between cross-border nodes can be expanded to limits of reasonable expansion capacities. For hydrogen, transmission infrastructure expansion is still not allowed. The allowance of more deployment of electricity transmission infrastructure is expected to lead to a redistribution of power generation plants.

Scenario 2.1

In this scenario, the same inputs and constraints apply as in Scenario 2. The only difference is that in this scenario the number of nodes where electricity can be converted to hydrogen gas by P2G-installations is extended. In previous scenarios these were only at nodes located near the North Sea, so-called coastal nodes. In this scenario these are also allowed for deployment in nodes that are located inland. This means that renewable energy generated from onshore installations are able to produce hydrogen to meet inland demand. This scenario has been designed in order to answer sub research question 4: *To what extent can the deployment of electrolysers on inland locations contribute to a cost-efficient energy system in the NSEC?*. In previous scenarios, hydrogen demand was either met by P2G-installations powered by offshore wind or by the import of hydrogen from outside the NSEC. An expected decrease in hydrogen transmission and hydrogen import might occur, as demand can be supplied more locally. The specification of coastal and inland nodes in shown in Table 11.

Scenario 2.2

For this scenario, the same inputs and constraints apply as in Scenario 2. What distinguished this scenario is the possibility of P2G-installations at offshore nodes. This has been designed in order to answer sub research question 5: *To what extent can the deployment of electrolysers on offshore locations contribute to a cost-efficient energy system in the NSEC?*. This means that electricity can be converted to hydrogen not only at coastal nodes, but also at offshore nodes. Thereby the hydrogen is allowed to be transmitted from offshore nodes to onshore nodes. As hydrogen transmission infrastructure has significantly lower costs than electricity transmission infrastructure, a potential lower energy system cost is expected compared to Scenario 2. The specification of offshore nodes in shown in Table 11.

Scenario 2.3

Again, this scenario is based on Scenario 2. For this scenario, the constraints to cross-border hydrogen transmission infrastructure are being lifted. This means that expansion of hydrogen transmission infrastructure is allowed when this contributes to an optimization of the whole energy system of the NSEC. Allowing this hydrogen transmission expansion will allow the analysis of sub research question 3: *How can the expansion of the electricity grid or hydrogen grid contribute to a cost-efficient energy system in the NSEC?*.

Scenario 2.4

This scenario allows for a further optimization of the energy system of NSEC by combining the inputs and constraints of Scenarios 2.1 and 2.3. This means that cross-border hydrogen transmission infrastructure can be expanded, while P2G-installations in onshore nodes can be deployed. Therefore, this scenario attempts to answer sub research questions 3 and 4. As this scenario allows more possibilities and requires less constraints, a further optimization of the total energy system costs is expected.

Classification of location per node	
Coastal	17_FR, 21_FR, 22_FR, 26_FR, 28_BE, 30_NL, 31_DE, 32_DE, 38_DK, 72_DK, 79_NO, 89_SE, 81_NO, 90_UK, 92_UK, 93_UK, 94_UK & 96_IE
Inland	14_FR, 15_FR, 16_FR, 18_FR, 19_FR, 20_FR, 23_FR, 24_FR, 25_FR, 27_FR, 29_LU, 31_DE, 33_DE, 34_DE, 35_DE, 36_DE, 37_DE, 80_NO, 82_NO, 83_NO, 84_NO, 85_NO, 86_SE, 87_SE, 88_SE, 91_UK & 95_UK
Offshore	01_UK, 02_UK, 01_NL, 02_NL, 01_DE & 01_DK

TABLE 11 - CLASSIFICATION OF NODES

4. RESULTS

For the analysis of the results, presented by the output of the scenario modelling that has been executed, different topics are addressed. These different topics highlight the different parameters that underlie the concluding findings of this study. First of all, the extent of self-sufficiency in electricity and hydrogen are addressed by the NSEC per scenario in Chapter 4.1. Thereafter, the deployment rates of the different renewable energy technologies per scenario are discussed in Chapter 4.2. In Chapter 4.3 the transmission values per scenario and other infrastructural system designs are presented. Following on that, Chapter 4.4 will discuss the required storage capacities for hydrogen in salt caverns per scenario. Finally, the total energy system costs per scenario are evaluated in Chapter 4.5.

4.1 ENERGY SELF-SUFFICIENCY OF NSEC

What is considered under the definition of self-sufficiency of NSEC is to what extent the countries are able to meet their demand in electricity and hydrogen by only considering the generation capacity of NSEC, without the possibility of imports from outside NSEC. In order to evaluate this, a separate percentage for the electricity demand and hydrogen demand are expressed. This is called the ENS, the Energy Not Served. For the analysis of this parameter, it is only relevant to look at Scenarios 0, 1.1 and 1.2. This is because all other scenarios allow for the import of hydrogen from outside NSEC and are therefore able to meet the demanded electricity and hydrogen by sources from outside the NSEC. In the results of all these scenarios the ENS for both electricity and hydrogen were 0, as expected. This ENS of 0 is possible, as the model does not consider the stochasticity of the supplied energy by the energy sources. This is explained earlier in Chapter 3.2.

When evaluating the ENS of Scenario 0, other outcomes are perceived. For electricity, a total of 106 TWh is not being served during the simulation of 2050. This is 5% of the total demanded electricity in 2050 in NSEC. For hydrogen, a total of 160 TWh is not being served, which a total of 28% of the total demanded hydrogen. These amounts show a significant gap between the demanded energy and the available generation capacity to meet this demand, considering the energy system constraints. Therefore, sub research question 1 can be partially answered; Scenario 0 is not able to provide the demanded electricity and hydrogen and further generation capacity expansion is required to meet all demand.

When looking at Scenarios 1.1.1 and 1.2.1, it appears that for both electricity and hydrogen there is a total ENS of 0 in the NSEC. As these scenarios allow the deployment of additional offshore wind and onshore PV and onshore wind, a sufficient amount of total generation capacity is available to meet all electricity and hydrogen demand in all countries. While in Scenario 0, the maximum amount of generation capacities is deployed for all technologies, this is not the case for the following scenarios. This is shown in Chapter 4.2.

To conclude, it can be stated that the renewable energy generation capacities of Scenario 0 are, as expected, not sufficient. Therefore, a larger deployment of offshore wind, possibly in combination with onshore renewables, is required to meet all demand.

4.2 Installed capacities of power plants

For the deployment of RES in each scenario, the amount of deployed GW per country is analyzed. Also, the production levels per technology in TWh are analyzed. For Scenario 0 and its subscenarios, a clear difference per scenario can be perceived. As mentioned before, in Scenario 0 the energy demanded cannot be served in all countries as the demand is higher than the potential supply. To be exactly, for Scenario 0 a total of 99.8% (882 GW) of the available generation capacity (883 GW) was deployed. The reason that this percentage can be lower than 100%, even though not all energy is served, is because of the provided transmission constraints in the model. As mentioned in Chapter 4.1, later scenarios are able to meet full demand. Nevertheless, Scenario 1.1 still requires 99.8% (1034 GW) of the available generation capacity in the NSEC (1036 GW) in this scenario. For Scenario 1.2, this dropped to a total of 89.9% (1159 GW of 1295 GW), as this scenario allowed for a larger deployment of onshore wind and PV. This means that not all generation capacity allowed to be deployed, is considered as required for deployment in order to meet the energy demand in the most cost-efficient way.

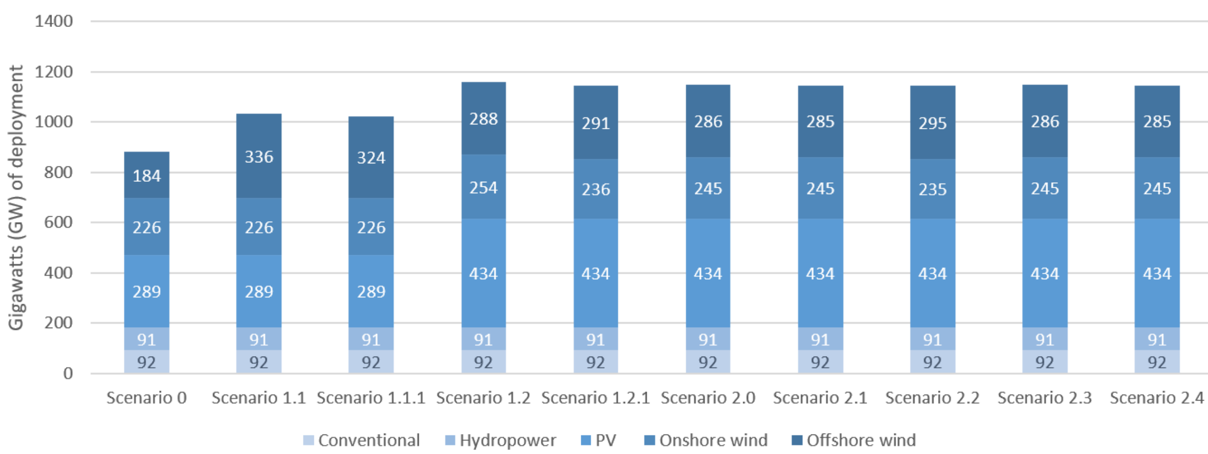

FIGURE 13 - DEPLOYMENTS PER TECHNOLOGY IN GW

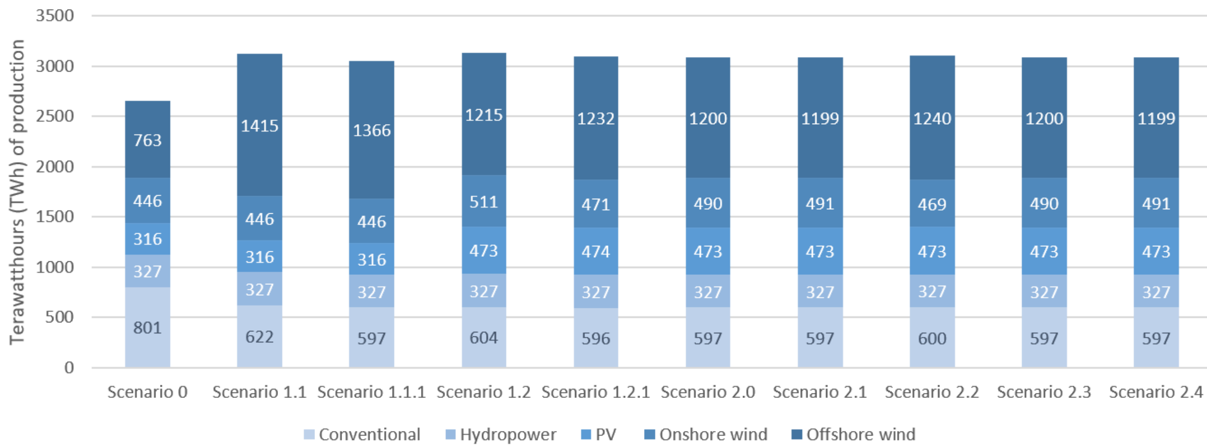

FIGURE 14 - PRODUCTION LEVELS PER TECHNOLOGY IN TWH

When evaluating the results of Scenario 0 and its subscenarios of the generation capacity deployments, it is shown that the allowance of a further deployment of onshore PV and onshore wind leads to a large shift in outcomes. The results are shown in Figure 13 and 14. When comparing Scenario 1.1 to Scenario 1.2, a decrease of 48GW of offshore wind (14.0%) and an increase of 145 GW (50.0%) of PV and 28GW (12.4%) of onshore wind is shown. This decrease in offshore wind is also shown in the produced TWh by offshore wind, as presented in Figure 14. This decrease of offshore wind is for the far majority found in offshore nodes, as the transmission of this electricity is most costly. The increase in onshore wind can be found in Germany, Denmark and Norway, while the increase in PV can be found over the entire NSEC. The reason for this change in deployment capacities per technology, is because of the lower CAPEX and OPEX of onshore wind and PV compared to offshore wind. This shows that the allowance of a higher deployment of onshore renewables enables a more cost-efficient energy system, as transmission of electricity over large distances is prevented.

When perceiving Scenario 2 and its subscenarios a more equal distribution of RES can be perceived. The only outlier can be found in Scenario 2.2. In this scenario, a decrease in onshore wind capacity can be found, while an increase in offshore wind capacity is shown. This is related to the allowance of electrolysers at offshore nodes and the transmission of hydrogen from offshore to onshore nodes. This enables a cheaper production of hydrogen offshore and therefore causes a small shift in deployment rates from onshore to offshore. When comparing Scenario 2.2 to Scenario 2.4, this increase in offshore wind can fully accounted for by offshore nodes, while the decrease in onshore wind can be solely found in Germany.

The scenarios show that a larger deployment of offshore wind or onshore renewables cause shifts in the optimal deployment capacities. It is shown that allowing more onshore renewables causes a decrease in offshore wind energy deployment, under the condition that all demand is served. Though, onshore renewables show a higher deployment capacity than offshore wind in the majority of the scenarios, the far majority of the produced electricity is produced by offshore wind energy. This is related to the higher capacity factor of offshore wind compared to both PV and onshore wind.

4.3 INFRASTRUCTURAL SYSTEM DESIGN

Regarding the transmission of electricity and hydrogen, different outputs are found. When evaluating the values shown in Figure 15 for Scenario 1 and its subscenarios, a clear difference can be perceived between Scenario 1.1 and 1.2. As in Scenario 1.2 a higher deployment capacity of PV and wind onshore is allowed, a lower transmission value for hydrogen is found than in Scenario 1.1. This is a result of the ability to meet electricity demand in inland nodes to a higher extent when onshore renewables are deployed in larger amounts. Because of that, the total transmission from offshore to inland can be reduced. Since the electricity transmission was at its limit already, the decrease of transmission is at the expense of the hydrogen transmission. When looking at 1.1.1 and 1.2.1, it shows that the import of hydrogen can have an impact as well. The required hydrogen imports in Scenario 1.1.1 and 1.2.1 are 58 TWh and 29 TWh, respectively. As shown, the allowance of hydrogen imports for Scenario 1.1 (in Scenario 1.1.1) results in a major decrease in transmission of hydrogen. On the other hand, the allowance of hydrogen imports for Scenario 1.2 (in Scenario 1.2.1) leads to a minor decrease in hydrogen transmission in the NSEC.

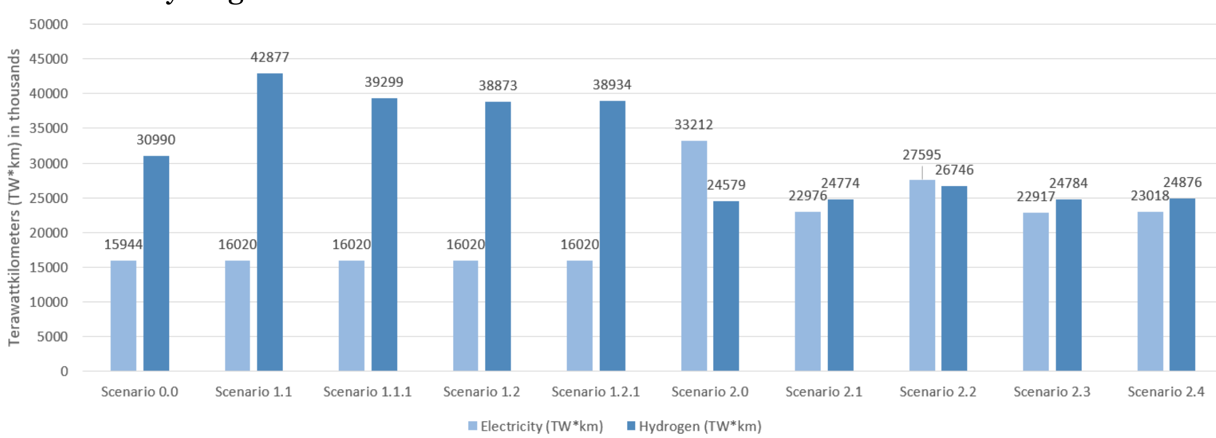

FIGURE 15 - TOTAL CROSS-BORDER TRANSMISSION VOLUMES PER SCENARIO IN TW*KM

A remarkable difference between Scenario 1.1 and Scenario 2.0 is that a higher allowance of electricity transmission capacity leads to an increase in transmission values for electricity. Though, the hydrogen transmission value decreases as a result of that. The allowance of more electricity transmission results in a further optimization of the electricity grid, causing more balanced transmission values for both energy carriers. As the distances between nodes in the model vary, electricity can be transported over shorter distances by allowing more electricity transmission infrastructure between those nodes. This allows Scenario 2.0 for a further optimization of electricity transmission than Scenario 1.1.

At Scenario 2.0 and its subscenarios, only minor differences can be observed. The only scenario that shows major different transmission values than its subscenarios, is Scenario 2.2. This scenario shows that the sighting of P2G installations at offshore nodes leads to an increase of both electricity and hydrogen transmission capacities. The electricity transmission capacity expansion is shown in the interconnectors from Norway to both Germany and The Netherlands. Regarding the hydrogen transmission, the capacity expansion is shown in the interconnections from The Netherlands to Belgium and Germany.

These results show that the allowance of imports of hydrogen from outside NSEC and the allowance of electricity transmission expansion lead to different infrastructure designs. When hydrogen imports are allowed, a reduction in the total hydrogen transmission is shown. When the electricity transmission is allowed to expand, it results in a major decrease in hydrogen transmission in favor of electricity transmission.

4.4 Salt cavern storage

When analyzing the results of the required hydrogen storage in salt caverns, significant differences per scenario can be observed. For Scenario 1 and it's subscenarios, every following scenario leads to further decrease of the required hydrogen storage, as the further allowance of deployment for renewables offers a more optimized energy system with a smaller amount of hydrogen storage demand. The only exception to this is Scenario 0, as this scenario was not able to meet the required electricity and hydrogen demand. The required storage capacities are shown in Figure 16. For the other scenarios, it can be stated that a both the allowance of hydrogen imports and the allowance of more PV and wind onshore lead to a lower level of required hydrogen storage.

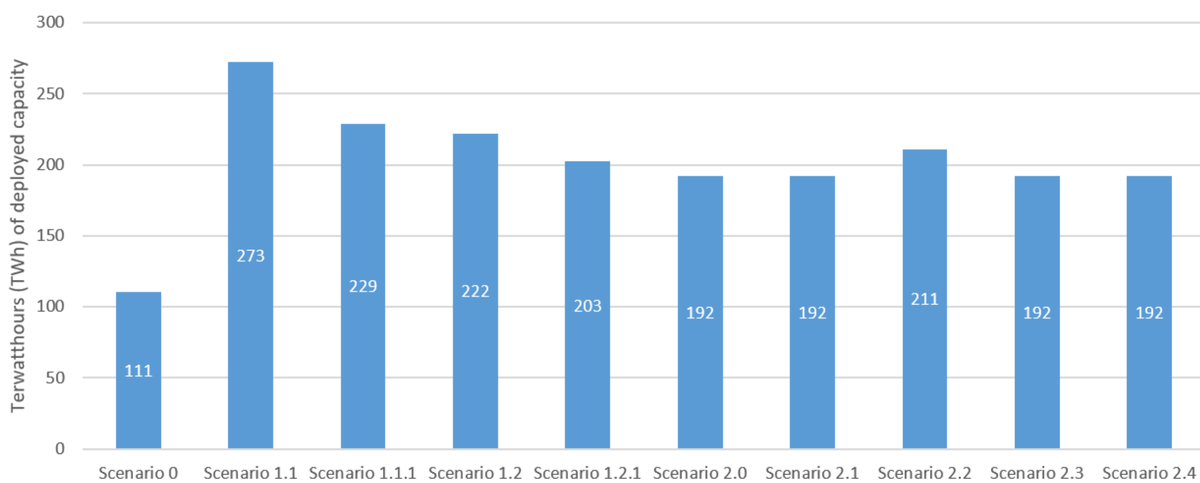

FIGURE 16 - REQUIRED HYDROGEN STORAGE CAPACITIES FOR SALT CAVERNS PER SCENARIO

For Scenario 2 and its subscenarios, a more similar result can be found. For all scenarios, except for Scenario 2.2, a similar required amount of hydrogen storage can be observed. This shows that different energy system design choices, as the expansion of the cross-border hydrogen transmission capacity and the allowance of P2G-installations inland, do not lead to a lower level of required hydrogen storage. Only when the siting of P2G-installations on offshore nodes and the transmission from hydrogen from offshore nodes to onshore nodes is allowed, an increase of 20 TWh (9.4%) is observed. Relevant to notice here is that 192 TWh of required hydrogen storage in salt caverns is 0.02% of the total technical potential storage capacity identified in NSEC by Caglayan et al. (2020).

These scenarios show that a further deployment of renewables and the import of hydrogen from outside the NSEC lead to a decreasing requirement of hydrogen storage for the NSEC. The hydrogen storage demand only increases when the production of hydrogen is allowed at offshore nodes.

4.5 Energy system costs

When evaluating the results of the total energy system costs of the scenarios, the differences between different scenarios are reviewed. For reviewing the energy system costs, the costs of power plants (investments and operational, including production), transmission and conversion are considered altogether. Evaluating the energy system costs altogether shows a better understanding of the interactions between the scenarios. As Scenario 0 (8.6% lower costs than Scenario 1.1) was not able to be self-sufficient and therefore had a very low total system costs compared to the other scenarios, Scenario 1.1 is taken as the benchmark scenario for the other scenarios. As shown in Figure 17, all subscenarios from Scenario 0 lead to a further decrease in total energy system costs. Both the import of hydrogen and the allowance of more PV and wind onshore contribute to a further cost-optimization of the energy system in the NSEC.

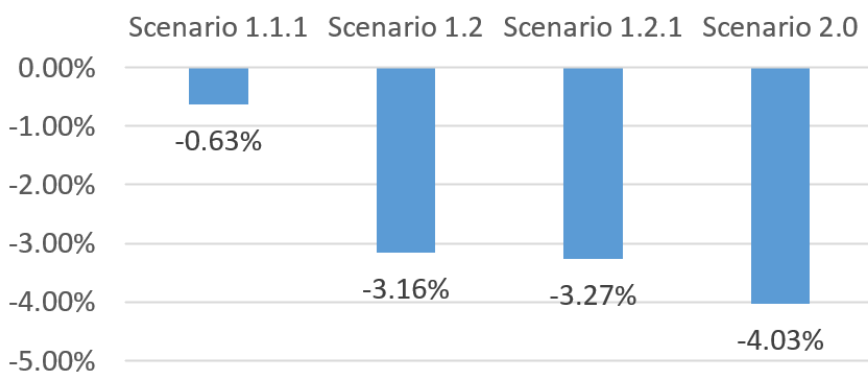

FIGURE 17 - PERCENTAGE OF DIFFERENCE IN SYSTEM COSTS COMPARED TO SCENARIO 1.1

When considering Scenario 2.0 and it subscenarios, a further cost-optimization can be observed. When comparing Scenario 2.0 to Scenario 1.1, a cost reduction of 4.03% can be observed. This means that a further optimization of the electricity transmission infrastructure by allowing higher transmission capacities leads to lower energy system costs. However, when comparing the subscenarios of Scenario 2.0 to Scenario 2.0, it can be observed that the system cost reductions are smaller. This is shown in Figure 18. As shown, despite the differences in transmission values and production capacities per scenario (which is shown in previous chapters), most of the scenarios do not stand out with a significant system cost reduction. The only scenario worth mentioning is Scenario 2.2, which shows a system cost reduction of 0.55% compared to Scenario 2.0 as a result of the allowance of offshore P2G-installations.

When observing all energy system cost levels, it can be observed that scenarios with smaller restrictions allow the energy system to become more cost-efficient. This is shown in Table 12, where all energy system cost levels are compared to the other scenarios. The only scenarios that have larger cost-efficiencies than its following scenarios, is Scenario 2.2. This is also shown in Figure 18. The reason for this is that Scenario 2.2 allows the offshore conversion to hydrogen gas and the transmission from offshore to onshore, while the following scenarios don't allow that. As shown, offshore hydrogen conversion still enables a larger system cost-reduction than the allowance of electricity, and hydrogen transmission infrastructure and the sighting of inland electrolysers. The relative large cost reduction of Scenario 2.2 can be credited to the cheaper transmission of hydrogen compared to the transmission of electricity.

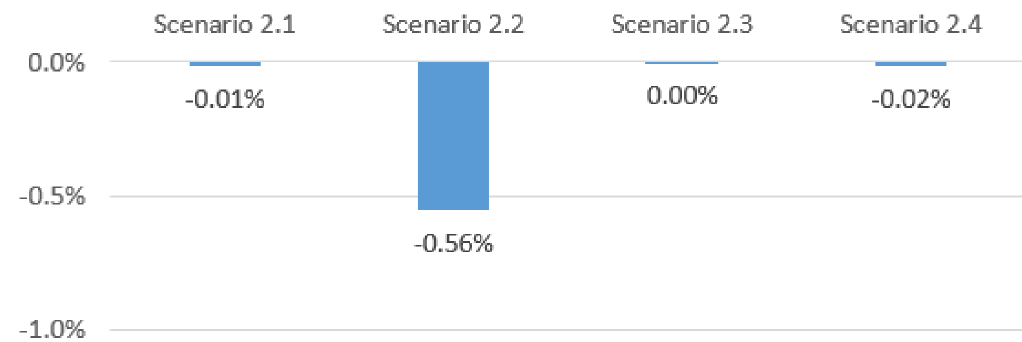

FIGURE 18 - PERCENTAGE OF DIFFERENCE IN SYSTEM COSTS COMPARED TO SCENARIO 2.0

	1.1	1.1.1	1.2	1.2.1	2.0	2.1	2.2	2.3	2.4
1.1		+0.63%	+3.16%	+3.27%	+4.03%	+4.05%	+4.57%	+4.03%	+4.05%
1.1.1	-0.63%		+2.55%	+2.66%	+3.43%	+3.44%	+3.96%	+3.43%	+3.44%
1.2	-3.16%	-2.55%		+0.12%	+0.90%	+0.92%	+1.45%	+0.90%	+0.92%
1.2.1	-3.27%	-2.66%	-0.12%		+0.79%	+0.01%	+0.56%	+0.00%	+0.02%
2.0	-4.03%	-3.43%	-0.90%	-0.79%		+0.01%	+0.56%	+0.00%	+0.02%
2.1	-4.05%	-3.44%	-0.92%	-0.01%	-0.01%		+0.54%	-0.01%	+0.00%
2.2	-4.57%	-3.96%	-1.45%	-0.56%	-0.56%	-0.54%		-0.56%	-0.54%
2.3	-4.03%	-3.43%	-0.90%	0.00%	0.00%	+0.01%	+0.56%		+0.01%
2.4	-4.05%	-3.44%	-0.92%	-0.02%	-0.02%	0.00%	+0.54%	-0.01%	

TABLE 12 – RELATIVE DIFFERENCES IN SCENARIOS (IN %), VERTICAL COMPARED TO HORIZONTAL

5. VALIDATION & SENSITIVITY ANALYSIS

In order to determine if the model, which is the main methodology of this research, is accurate and valid, an assessment has to take place. This assessment consists of a model validation and a sensitivity analysis. In the model validation, a qualitative assessment will describe the level of accuracy and the validity of the model while a sensitivity analysis analyzes the robustness of the model based on a quantitative assessment.

5.1 MODEL VALIDATION

For the determination of the correctness of a simulation model, a validation is executed. A validation for a model aims to allow the substantiation of a model, where the applicability shows a satisfactory range of accuracy which is consistent with the intended application of the model (Sargent, 2013). For this validation, multiple methods are available. Applicable validation methods for energy system validations are historical data validation and the comparison to other models. Nevertheless, these validations methods are not applicable to this research. The historical data validation is not applicable for this model as the model in this research focusses on future projections of the energy system with attributes (as hydrogen cross-border transmission, hydrogen storage and large-scale CCS) that are not yet part of the current energy system in the NSEC. Therefore, this validation method cannot be executed. When considering the method where the model of this research is compared to the outcomes of other models, it has to be mentioned that the scope of this research is different than any other conducted research. This is explained in subchapter 2.1 of this research. Because of this different scope, a comparison to other models is not considered as valuable.

Still, a validation of the Powerfys model can be performed by performing a historic validation. As mentioned in Chapter 3.1, this model has been used for previous research by Guidehouse. In previous research, the electricity system of the NSEC has been researched. For this research, the structure of the model and the design have remained the same. The only adjustments that have been made are the additions of an energy carrier (hydrogen), including the required transmission infrastructure, storage and demand. As the model has been performing well in previous research by Guidehouse, it can be assumed that this model can also be considered valid for the performance of this research.

In addition to that, Powerfys model has been based on the stELMOD model by Abrell & Kunz (2014). The study itself performs an extensive validation of the model according to the historical data validation method. Besides that, this stELMOD model has been reviewed and applied in over 10 other studies that have been found (Zepter & Weibezahn, 2019) (Bjørndal, Bjørndal, Midthun, & Tomasgard, 2018). This contributes to the assumption that this stELMOD, and therefore also the Powerfys model, can be considered as a valid model.

Besides that, this model can be validated by applying the method of face validation. Face validation concerns the explanation of individuals knowledgeable about the model whether the logic of the concepts in the model are correct and reasonable. In order to evaluate the correctness and reasonableness of this model, three different concepts of the model are evaluated. These three concepts are: the topology of the model (subchapter 5.1.1), the energy generation mix (subchapter 5.1.2) and the import and transmission of hydrogen (subchapter 5.1.4) in the model.

5.1.1 Topology

For the energy system modelled in this research, a topology of the geographical scope has been made. In total 50 nodes have been used in this model: 44 onshore nodes and 6 offshore nodes. In order to model the real existing energy system in NSEC, a topology should be developed with a substantial higher number of nodes. Nevertheless, simplifications of the real energy system with a limited number of nodes are necessary for conducting analysis. It is necessary as the computational power for simulating models is limited and because data required for the model is more available for large geographic resolutions than at small geographic resolutions. Also, other energy system models use a so-called 'regionalization', with a simplification of the transmission of energy from region to region (Reuss, et al., 2019). Nevertheless, this simplification of the real-world causes inaccuracies of the model compared to the real energy system. These inaccuracies in the model design and inputs thus cause that the outcomes presented in this research fully comply with reality. Nevertheless, this study provides insights and draws conclusions on a system-level, instead of a regional or national level. For this reason, it can be assumed that the topology used in this model is able to deliver valid outcomes for this study.

5.1.2 Power plants parameters

As mentioned before, the model which has been used in this research shows a simplification of the energy system in reality. Also, the power plants that can be deployed in the model form a simplification. In this model, the CAPEX and OPEX and fuel costs for a certain type of power plants is equal in every country of NSEC. In reality, the costs for every power plant are different as many elements determine the cost levels at a certain location at a certain time. Examples of those elements are the age of the power plant, the efficiency of the power plant and the labor costs in a certain country. For offshore wind turbines location also causes variations in capital costs, as turbines are deployed in different water depths. Still, these deviations in cost levels are minor compared to the cost levels of other renewable energy technologies. Therefore, it is not expected that elaboration on offshore wind cost levels per region or location would result in different study outcomes, as this study derives conclusion only on a system-level scope. For that reason, the used cost levels in this model can still present valid outcomes for this study.

5.1.3 Import of hydrogen

As the import of hydrogen from countries outside NSEC is perceived as a viable possibility for meeting hydrogen demands, these imports had to be allowed in the model. To integrate these hydrogen imports in the model, the choice has been made to develop artificial power plants in the regions where hydrogen could be imported into NSEC. These fictive power plants can produce hydrogen without requiring any materials for the production. This fictive power plant can have different price mechanism than the import of hydrogen would have in reality. An example for this is that hydrogen imports can have different price levels during the year, while the fictive power plant in the model operates at the same cost parameters during the entire year.

5.1.4 Transmission of hydrogen

One important characteristic of transmission networks of gaseous formations compares to transmission networks of electricity is the ability to temporarily store energy in the transmission infrastructure. This energy can be stored by increasing the pressure in the pipelines. By storing hydrogen in the transmission infrastructure, it is possible to limit the demand for hydrogen storage in salt caverns or to reduce the variations in demanded hydrogen for a certain region. The model of this research is not successful to integrate the potential storage capacity of hydrogen pipelines in this model and handles the hydrogen transmission network with the same properties as the electricity transmission network. Therefore, the outcomes of this research do not reflect the potential storage capacity of hydrogen transmission networks.

5.2 Sensitivity analysis

This research is based on different parameters, which have been retrieved from different sources. These different resources have all provided projections for the year 2050, but with different methodologies. These different projection methodologies can lead to different outcomes, especially when projections are made for a time horizon of 30 years as in this case. In order to understand the consequences of the input parameters that have been used in this model, a sensitivity analysis has been conducted. This sensitivity analysis will show to what extent the used input parameters affect the outcomes of this research. For the sensitivity analysis, Scenario 2.4 has been chosen as the baseline scenario. In this chapter, the methodology of this sensitivity analysis is firstly explained in subchapter 5.2.1. Thereafter, the results of this analysis are presented in subchapter 5.2.2 (sensitivity on hydrogen imports), subchapter 5.2.3 (sensitivity of installed capacities of P2G) and subchapter 5.2.4 (sensitivity of installed capacity of power plants). Finally, a small summary is presented which concludes the results of the sensitivity analysis.

5.2.1 Methodology of sensitivity analysis

As mentioned, the large time frame of 30 years towards 2050 can lead to projected costs that are inaccurate to the real costs in 2050. With technologies as PV, cost estimations for 2020 made in previous decades have turned out to be very conservative (Hoekstra, 2019). As the technology of hydrogen production by electrolysis and the large-scale storage of it are still novel, the learning-curve for this technology drives uncertainty of future cost reductions (Schmidt, Hawkes, Gambhir, & Staffell, 2017). Therefore, the sensitivity on the hydrogen imports, the installed capacities of P2G plants and power plants are analyzed. This is done by adjusting the input parameters of hydrogen import costs, hydrogen storage costs and the costs of P2G plants. These three different parameters are all tested considering Scenario 2.4, which is the final scenario that has been executed in this research. This scenario is taken as the base case. The exact parameters and assumptions made in this scenario, can be found in Chapter 3.6. For the variation of the hydrogen import price, the fuel price of the virtual power plant is adjusted, while for the hydrogen storage costs and the P2G-plants costs the CAPEX and the fixed OPEX (as percentage of CAPEX) values are adjusted. All parameters are adjusted from -40% of the original parameter in Scenario 2.4 to +40%, with steps of 20%. The reasons for these steps are the high uncertainty of the numbers, as mentioned in the beginning of this paragraph. The number of simulations per sensitivity were limited due to time and resource restrictions. A sensitivity is considered as significant, when the outcomes of the 40 percent deviation are bigger than a 5 percent difference compared to the base case cost level. The definition of significance at 5 percent has been chosen as most sciences propagate this level as significant. In the following paragraphs, the three different sensitivity analyses are elaborated.

5.2.2 Sensitivity of hydrogen imports

For the sensitivity of hydrogen imports, it can be stated that the amount is highly sensitive to cost deviations in hydrogen storage, hydrogen import or P2G installations. This is shown in Figure 19. In the base case, hydrogen imports are 27 TWh. This is equal to 4.7% of the total hydrogen demand in the NSEC. This amount of the base case is shown in the figure by the black-striped line. In Table 13, the relative deviations (in percentages) are presented for each scenario.

As shown, the cost of hydrogen imports has a high impact on the hydrogen import that is demanded. If the cost is 40% lower than at base case, the demanded hydrogen import is 264 TWh. This is 46% of the total demanded hydrogen in the NSEC. Figure 19 shows an almost linear relationship at the 40% and 20% lower cost levels for hydrogen imports. This can be explained by the direct correlation of price and demand of hydrogen import. Based on this, it can be estimated that all hydrogen demanded will be imported at a price level of 85-90% lower than the base case. On the other hand, if the cost is 20% higher than base case, the demanded storage capacity is zero. Possibly, the amount of zero import is reached at a smaller percentage than 20%, in particular when considering the mentioned linearity. Nevertheless, this cannot be confirmed as no simulation with percentages between 0% and 20% has been performed. To conclude, this analysis shows that a higher cost of hydrogen imports leads to a significant decrease in demanded hydrogen imports.

For the CAPEX of hydrogen storage, another high impact can be perceived. At a CAPEX of -40% and -20% of the base case, the demanded storage capacity is still 0 TWh, while a CAPEX of +20% and +40% shows demanded capacities of 79 TWh and 102 TWh, respectively. This confirms that a higher CAPEX and fixed OPEX of hydrogen storage facilities leads to a significant increase in demanded hydrogen imports. This can be attributed to the fact that the costs of hydrogen storage and the imports of hydrogen are negatively correlated; if one becomes more expensive, the other will become more demanded.

Last of all, the impact of the CAPEX of P2G installations is less significant, as the range of outcomes is smaller. Demanded hydrogen imports at different CAPEX and fixed OPEX of P2G plants range from 8 TWh at -40% of base case to 41 TWh at +40% of base case. Still, it can be stated that a higher CAPEX of P2G installations results in a significant increase in demanded hydrogen imports.

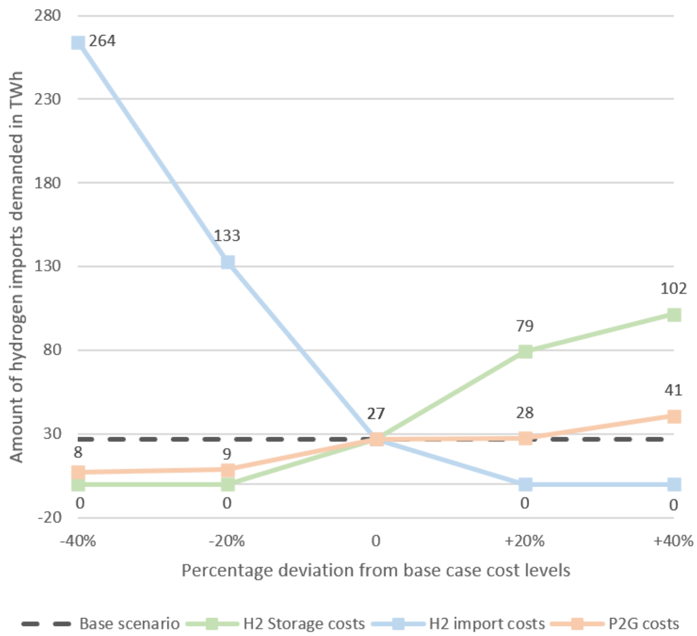

FIGURE 19 - SENSITIVITY ANALYSIS ON HYDROGEN IMPORTS

	H2 Storage costs	H2 import costs	P2G costs
-40%	-100%	+878%	-70%
-20%	-100%	+393%	-67%
+20%	+193%	-100%	+4%
+40%	+278%	-100%	+52%

TABLE 13 - RELATIVE DEVATIONS IN HYDROGEN IMPORTS FROM BASE CASE PER SCENARIO

5.2.3 Sensitivity of installed capacities of P2G

For the sensitivity of the installed capacities of P2G installations, a smaller sensitivity towards the cost differences in hydrogen storage, hydrogen import and P2G installations can be perceived. In Figure 20 this sensitivity analysis is graphically presented, while Table 14 shows the relative deviations of each scenario compared to the base case.

Similar to the previous sensitivity analysis, the costs of hydrogen imports show the highest sensitivity. At a hydrogen import cost of 40% lower than base case of 125 GW, the demanded installed capacity of P2G is 101 GW. If the cost is only 20% lower than base case, the capacity is 113 GW. If the cost is 20% higher than base case, the level of installed capacities is 132 GW (+6%). This same capacity level applies when the cost is increased to 40% of base case. The reason that the capacity doesn't increase even further, is because at +20% the hydrogen imports are already equal to zero. This means that at this level all hydrogen demand is already met by P2G-installations. A higher level of P2G deployment is therefore not necessary. Thus, it can be stated that the cost level of hydrogen imports has a significant impact on the installed capacity levels of P2G in the NSEC. This high sensitivity can be explained by the direct relationship between hydrogen imports and P2G installations; if hydrogen imports become cheaper, the demand for hydrogen imports will increase. This comes at the expense of the domestic hydrogen production, produced by P2G installations.

When considering the impact of hydrogen storage costs, a smaller sensitivity can be perceived. At a CAPEX of -40% of the base case, the installed capacity is 139 GW. This decreases to 134 GW at a CAPEX of -20% of the base case. When CAPEX exceeds the base case with +20% and +40%, the levels of installed capacities of P2G are 113 GW and 109 GW, respectively. Therefore, it can be stated that deviations in CAPEX of hydrogen storage leads to a moderate deviation in the level of installed capacities of P2G. This more moderate sensitivity can be attributed to the indirect relationship of P2G installations and hydrogen storage. This can be explained as following; an increase in P2G installations leads to a higher supply of hydrogen. If this higher supply cannot (directly) be used to meet demand, it has to be stored. But if this storage becomes more expensive, the total cost of hydrogen increases, leading to a lower demand for P2G installations as well.

Finally, the sensitivity for the CAPEX of P2G installations on levels of P2G installed capacities is limited. At a CAPEX of -40% of the base case the installed capacity was 136 GW, while this decreased to 131 GW at -20% of the base case. With increases in CAPEX of P2G installations compared to the base case, the deviations became even smaller with 124 GW and 121 GW at a CAPEX of -20% and -40%, respectively. Therefore, a very low sensitivity can be concluded from the CAPEX of the P2G installations on the level of installed capacity. This can be considered as remarkable, as a direct relationship between price and quantity of P2G installations can be expected. This analysis shows that the price of P2G installations has a subordinate effect on the quantity of P2G installations in the NSEC than other cost levels.

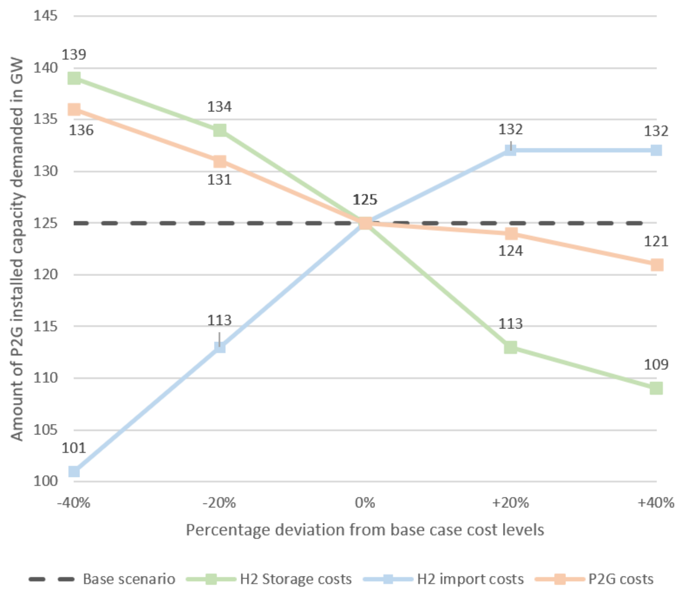

FIGURE 20 - SENSITIVITY ANALYSIS ON INSTALLED CAPACITIES OF P2G

	H2 Storage costs	H2 import costs	P2G costs
-40%	+11%	-19%	+9%
-20%	+7%	-10%	+5%
+20%	-10%	+6%	-1%
+40%	-13%	+6%	-3%

TABLE 14 – RELATIVE DEVIATIONS IN INSTALLED CAPACITIES OF P2G FROM BASE CASE PER SCENARIO

5.2.4 Sensitivity of installed capacities of renewable energy power plants

Last of all, the sensitivity of installed capacities of renewable energy power plants in NSEC is analyzed. For all three parameters a very low sensitivity is shown in this analysis, as displayed in Figure 21. These sensitivities are also shown in Table 15, in percentual differences to the base case.

The cost of hydrogen imports results, again, in the highest sensitivity of this analysis. At a cost level of -40% of the base case of 740 GW, the RE installed capacity is 648 GW. For -20% of the base case, the installed capacity increased to 710 GW. When increasing the cost of hydrogen imports, the RE installed capacity is 750 GW for both +20% and +40% of the initial hydrogen costs. The RE installed capacity is the same for both levels, as the hydrogen imports already equals 0 at +20%, which means that no further RE capacity has to be deployed to meet hydrogen demand. To summarize, this reveals a very moderate sensitivity of hydrogen import costs on the level of RE installed capacity. The reason that the cost of hydrogen imports still has the highest effect on the total RE installed capacity, is because of the direct correlation. If the cost of hydrogen imports decrease, the demand of hydrogen imports will increase. This leads to a decrease in demand for domestically soured hydrogen, which means that a smaller amount of renewables have to be deployed to meet the hydrogen demand. Though, the sensitivity is only moderate because the renewables of NSEC in the model are not only deployed for the production of hydrogen (with the use of P2G installations), but also for the production of electricity to meet the electricity demand in NSEC.

For the CAPEX of hydrogen storage, the sensitivity analysis shows a minor effect. At a CAPEX of -40% and -20% of the base case, the installed capacity levels are 751 GW and 748 GW, respectively. When CAPEX is at +20%, the installed capacity decreases to 727 GW. A smaller decrease to 724 GW is noted when CAPEX is increase to +40% of the base case. This underlines the minor sensitivity of hydrogen storage costs on the RE installed capacity. The minor sensitivity is, just as for the hydrogen imports, related to the limited amount of renewables that is deployed for the generation of electricity used for the production of hydrogen. The majority of all generated electricity is used to meet the electricity demand in NSEC.

Also, the sensitivity for the CAPEX of P2G installations is very low. At a CAPEX of -40% of the base case the installed capacity is 746 GW and at a CAPEX of -20% the installed capacity is 743 GW. At a CAPEX of +20% the installed capacity is equal to the capacity at base case (740 GW) and +40% the installed capacity decreases to 737 GW. In conclusion, it demonstrates that none of the three parameters have a high impact on the installed capacity of renewable energy in the NSEC. This is for the same reason that is mentioned in the previous paragraph.

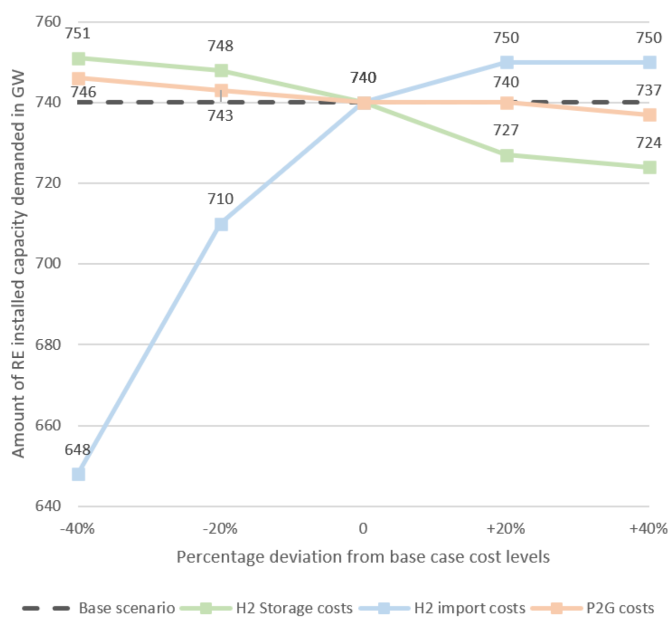

FIGURE 21 - SENSITIVITY ANALYSIS ON RE INSTALLED CAPACITY

	H2 Storage costs	H2 import costs	P2G costs
-40%	+1%	-12%	+1%
-20%	+1%	-4%	+1%
+20%	-2%	+1%	0%
+40%	-2%	+1%	0%

TABLE 15 – RELATIVE DEVIATIONS IN RE INSTALLED CAPACITY FROM BASE CASE PER SCENARIO

5.2.5 Summary of sensitivity analysis

In this sensitivity analysis, the price sensitivity on three different price parameters have been analyzed. For the hydrogen imports, it can be stated that this can be considered as highly sensitive to different price levels. In all three sensitivity analyses it is shown that the outcomes significantly change when the cost levels deviate from the base case scenario. For the installed capacity levels of P2G, it can also be stated that it shows a significant sensitivity, even though this sensitivity is smaller than the previous analysis. For this analysis, the hydrogen import price, still causes the largest sensitivity. On the other hand, the other two parameters show a smaller, but still significant, sensitivity. Finally, it is shown that different price levels do not cause a significant sensitivity on the capacities of installed renewable energy. In this analysis, it is shown that only small deviations from the base case are visible at all three different parameters.

6. Discussion

In this study, different scenarios for the energy system of NSEC for 2050 are analyzed to determine the most cost-efficient energy system design. The outcomes of this study will be discussed in this chapter. First of all, answers to the research questions will be provided in Chapter 6.1. Following, Chapter 6.2 will discuss how the design of the model and the presented result can relate to other studies that have been discussed in Chapter 2. Furthermore, the limitations of this study will be discussed in Chapter 6.3. Last of all, recommendations for future research on this topic are provided in Chapter 6.4.

6.1 Answers to the research question

In order to answer the main research question of this study, first the five sub research questions have to be answered. These answers are provided per sub research question. Finally, the main research question will be answered.

1. <u>To what extent is the deployment of offshore wind and onshore renewables necessary to meet the demanded electricity and hydrogen in the NSEC by 2050?</u>

This study shows that for meeting the demand of both electricity and hydrogen in the NSEC, renewables for both onshore and offshore have to be deployed in large extents. In the most cost-efficient scenario, Scenario 2.4, this considers 285 GW of offshore wind, 245 GW of onshore wind, 434 GW in PV when also allowing an additional 91 GW hydropower and 92 GW of conventional power plants. For offshore wind this means that deployment of offshore wind at near-shore locations and on shallow sea beds only will not be sufficient to meet the required capacities. Therefore, future energy scenarios should also further research the potential of floating offshore wind deployment in the far offshore and deep sea beds that are available to the NSEC region.

2. <u>How can the import of hydrogen from outside NSEC contribute to a cost-efficient energy system in the NSEC for 2050?</u>

The NSEC could potentially meet all electricity and energy demanded by those countries in 2050, without the import of hydrogen. Nevertheless, research shows that a more cost-efficient solution is to import a relatively small amount of hydrogen from outside the NSEC. This amount is equal to around 4-5% of the total hydrogen demand.

3. <u>How can the expansion of the electricity grid or hydrogen grid contribute to a cost-efficient energy system in the NSEC for 2050?</u>

For electricity transmission, it can be stated that the expected grid development plans for 2040 are largely sufficient to develop a cost-efficient energy system in the NSEC by 2050. Further expansion allowances of the electricity grid will lead to minor cost-efficiencies.

For hydrogen, this study shows that no further expansion than the planned natural gas grid for 2040 has to be considered, under the condition that this infrastructure will be fully retrofitted and available for hydrogen transmission. This can be considered as remarkable, as hydrogen physically has a lower energy density than methane gas. Nevertheless, two important reasons can be noticed why the grid still could be sufficient. The first reason is the large extent of electrification in the industrial sector (and built environment, but this is out of scope for this study), which leads to a smaller demand of gas. The second reason is that methane gas can only be sources at a small number of locations, meaning that transmission is required extensively to serve all areas with methane gas. On the other hand, (green) hydrogen can be sourced at almost any location. The only natural requirement is the availability of wind and sun. Therefore, hydrogen can be sourced more decentral than methane gas and therefore lower amounts have to be transmitted from one region to the other.

4. <u>To what extent can the deployment of electrolysers on inland locations contribute to a cost-efficient energy system in the NSEC 2050?</u>

As mentioned in the previous research question, inland deployment of electrolysers can contribute to a smaller transmission of hydrogen from the North Sea to inland locations. This smaller amount of transmission subsequently leads to a further cost-efficiency of the energy system in the NSEC. Nevertheless, this deployment of electrolysers at inland locations doesn't need to major cost-efficiencies. This is for the reason that the utilization rates of electrolysers with offshore wind are higher than for onshore wind and PV. This diminishes the cost-savings that are achieved with a small amount of transmission.

5. <u>To what extent can the deployment of electrolysers on offshore locations contribute to a cost-efficient energy system in the NSEC 2050?</u>

Further cost-reductions could be achieved, when P2G-installations are not only placed on shore, but also at offshore locations. By allowing P2G installations at offshore locations, transmission of electricity from offshore wind can be reduced and can instead be transported via hydrogen transmission pipelines, which offers a cheaper alternative to transporting electricity from offshore to onshore before converting it to hydrogen.

When answering the main research question '*What energy system design choices contribute to a cost-efficient energy system for the NSEC in 2050, when considering the electricity and hydrogen demands for 2050?*', it can be stated that the utilization of the gas infrastructure can contribute to a large extent to a cost-efficient energy system design in the NSEC for 2050. This gas infrastructure, utilized for hydrogen, is able to reduce electricity curtailment and transmission congestion, provide long-term energy storage and provide a sustainable energy source for the industries which face difficulties to electrify their operations. In order to guarantee security of supply in all countries, large amounts of both offshore and onshore renewables have to be deployed.

6.2 Comparison to previous literature

Compared to studies of Brown, Slachtberger, Kies, Schramm, & Greiner (2018) and Gils, Scholz, Pregger, Luca de Tena, & Heide (2017), this study shows that a smaller expansion of the current electricity transmission infrastructure is required for developing a cost-efficient energy system design while deploying large quantities of renewable energy. Brown et al. (2018) has shown that the current electricity transmission grid has to be multiplied by 6.5 to realize a cost-efficient electricity system.

This study shows an expansion of 50% leads to the most cost-efficient energy system (as shown in Scenario 2.4). This study assumes the electricity grid determined by e-Highway (2015) in 2050, which is approximately double the capacity of today's network. Therefore, this research comes to a three-fold of today's electricity transmission capacity. This is half of the capacity expansion suggested by Brown, Slachtberger, Kies, Schramm, & Greiner (2018). One explanation for the large difference between both studies is that this study only focusses on the countries surrounding the NSEC, where Brown, Slachtberger, Kies, Schramm, & Greiner (2018) concerned the entire continent of Europe. This is relevant as the study concerns countries which do not have access to seas where potentially a large share of the national energy demand can be produced. As a result of that, these countries will be required to develop large transmission infrastructure with countries that can supply them with energy from offshore wind.

Another explanation for the different outcomes of this and other studies, is the role of hydrogen as an energy carrier. This study allowed the production and transmission of hydrogen as an alternative energy carrier than electricity, while previous studies did not allow this. For instance, in Brown, Slachtberger, Kies, Schramm, & Greiner (2018) hydrogen was only allowed as an application for electricity. Therefore, no transmission of hydrogen between different nodes was allowed. The transmission of hydrogen, as a relatively cheap energy carrier to transport over large distances, is what can result in significant congestion reductions on the electricity transmission infrastructure. Therefore, large expansion of the electricity transmission grid can be prevented when also integrating the development of a hydrogen transmission infrastructure in the energy system model.

6.3 Study limitations & validation

The results that are presented, are based on a model with multiple input parameters and assumptions made in order to execute this research within the limits of the time and resources available for this study. Assumptions on model design and on input data caused that this model has several limitations that might affect the outcomes of this study.

One of the major limitations in data availability of this study was the lack of data regarding the transmission infrastructure of natural gas. Despite extensive research and enquiries at several national TSOs, no data has been found on the transmission infrastructure for natural gas within the country borders of the United Kingdom, France, Germany, Denmark, Sweden and Norway. Because of the lack of data, the assumption has been made that the transmission of hydrogen gas within country borders is unlimited, according to the copper-plate model. Also, no data has been found on the capacities of offshore natural gas transmission infrastructure for pipelines that are not leading directly from one country to another. In Figure 6 it is clearly shown that the North Sea holds many gas transmission infrastructures that ends up far offshore, connecting to multiple other pipelines. The only transmission capacities found, are the capacities of transmission infrastructure going from on specific country to another. Therefore, only these transmission capacities are considered when developing the model. The consequence of this is that the available gas transmission capacity in Europe is bigger in reality than what is assumed in this study.

This research simulates the development of an energy system in 2050, which is 30 years from to date. For this reason, parameters that have been used as input data for the model are assumed with uncertainty. To indicate to what extent different values of input data would result in different outcomes of this study, a sensitivity analysis is executed. This sensitivity analysis had shown that different price levels will only lead to significant deviations of the hydrogen imports for the NSEC. As the amount of hydrogen imports in the NSEC compared to the total demand of hydrogen is small (4-5% or less in all simulations), it can be stated that a deviation in hydrogen import caused by different price levels will not lead to large difference in the overall results of this study.

6.4 Future research

As this research shows shortcoming and limitations in resources and time, recommendations can be made regarding the further research on these topics. When considering future research project on the development of the energy system in NSEC, different topics are recommended to investigate. First of all, research could be focused on the impact of allowing the storage of hydrogen in transmission infrastructure by increasing and decreasing pressure of the pipelines. By investigating this potential, an assessment can be given on impacts of this for the required hydrogen transmission infrastructure and storage capacity. Another topic for future research is the assessment of the costs and benefits of P2G on offshore locations and the consequences on the design of the entire energy infrastructure of the NSEC. In addition to that, future research could be focused on the economic potential of salt caverns suitable for hydrogen storage. This research showed that only 0.02% of the total technical potential storage capacity identified in the NSEC is required for the demanded amount of hydrogen storage, but still the questions is if this amount is economically viable or not. Last of all, the United Kingdom leaving the European Union has caused that it left the NSEC consortium of countries. This brings major uncertainties about the commitment of the United Kingdom to international developments as the North Sea Wind Power Hub. The United Kingdom has the potential to deploy large amounts of offshore wind, but also a large projected demand of both both electricity and hydrogen in 2050. Therefore it brings a large contribution to the energy system of the NSEC as designed in this study. With the uncertainty caused by the Brexit, it would be recommended to provide another study of the energy system design for NSEC in 2050 without the United Kingdom.

7. CONCLUSION

This research aimed at answering the following research question:

How can the energy system of the NSEC be developed in the most cost-efficient way in order to supply the electricity and hydrogen demanded by those countries in 2050?

The answer to this research questions is given by the scenarios that have been executed based on the six sub research questions. The results of this research show that the NSEC is able to meet the entire hydrogen and electricity demand in the NSEC without the dependency on imported hydrogen from outside NSEC. Nevertheless, allowing hydrogen imports would create a more cost-efficient energy system. When allowing hydrogen imports, this study shows that only a fraction of approximately 5% of the total demanded hydrogen demand will be served by imports. This means that only at some moments in time and in some regions, it is more cost-efficient to import hydrogen than to deploy additional renewables and electrolysers. What has to be noted here, is that the imports of hydrogen are heavily sensitive on the price levels of electrolysers, hydrogen storage and the actual import price of hydrogen in 2050. As the technologies of hydrogen are still in development, expected price levels for 2050 are determined with large uncertainties. Higher hydrogen import volumes result in lower capacities of renewable energy deployment in order to meet the electricity and hydrogen demand.

When considering the further expansion of the electricity and hydrogen transmission grid, it can be concluded that a further expansion of the projected electricity grid for NSEC in 2040 by ENTSO-E will lead to further cost-efficiencies of the entire energy system. In contrast to that, a further expansion of the projected grid of natural gas in 2040 by ENTSO-G would not lead to further cost-efficiencies of the energy system costs. Therefore, it can be stated that a full retrofit of the current projected natural gas infrastructure in 2050 offers sufficient capacity for transmission of all hydrogen in NSEC. The research shows that the siting of P2G installations at inland regions do not lead to further cost-efficiencies of the energy system compared to only siting those at coastal regions. What does lead to significant cost-efficiency is the deployment of P2G installations at offshore hubs, while transporting the produced hydrogen via gas infrastructure to the shore. Compared to the transmission of electricity from offshore wind to the shore with P2G installations located onshore, this offers a more cost-efficient alternative. At this moment, P2G installations on offshore locations is still a novelty and therefore the prospects of this success are still uncertain.

Regardless of the design choices that will be made, the energy system for the NSEC requires a large expansion in deployment of renewables, both offshore and onshore, and in the expansion of electricity transmission for the decades to come. On top of that, the current natural gas grid can play a key role in the zero-carbon energy system of the NSEC for 2050 by transmitting large quantities of hydrogen, which will be produced in a large extent by renewable energy from the NSEC.

8. Reflection

Twelve months ago, when I started writing this thesis, I expected a totally different journey. Though, I think everyone on planet Earth had expected a totally different year. In the year 2020, the Covid-19 pandemic hit the world and caused many daily practices of our normal life to stop; schools and universities had to close, travelling and commuting were either banned or minimized and almost everyone had to start working from home.

Where I expected that I would be able to surround myself with inspiring colleagues, working on innovative sustainability strategies or renewable energy project developments, I ended up writing my thesis at home. Of course it is not with certainty to say, but I am quite sure that writing my thesis from home made this journey a lot harder for me than writing it (mostly) in the office of Guidehouse in Utrecht. I really missed the interactions with like-minded colleagues, the updates about interesting project and new insights they could have provided on my thesis. Because of the long and stressful journey it took to write this thesis, it now feels hard to take a lot of pride out of the work I have delivered. On the other hand, in a few years I can say that I did write a Master's thesis during a pandemic and I am sure that will fulfill me with pride after all.

What currently does makes me proud and humble, is that I have been able to write my thesis about a visionary project as the North Sea Wind Power Hub. The road to working on that topic is an interesting journey. In 2015 I started gaining interest in the energy transition. During that year I did an accountancy internship at Van Oord in Costa Rica and Dubai. At the same time, Van Oord was constructing the first commercial offshore wind farm of the Netherlands, Gemini. Also, in 2015, the Paris Agreement was signed and that triggered me to start following the news more closely about the transition that had already started, but that was about to take off. For that reason, I decided to start working in the energy sector for a year, at Vattenfall, after graduating from my Bachelor in Business Administration. This year at Vattenfall convinced me to not continue studying at a management faculty but switch to a Master focused on the energy transition. This became the MSc. Industrial Ecology.

In the year at Vattenfall I read about a vision presented by Tennet about the development of islands in the North Sea. These islands would become a hub for wind energy generated in the North Sea. With my growing interest in renewable energy and my previous experience of developing islands at Van Oord, this project really caught my attention. The opportunity that Guidehouse granted me three years later, at the end of my Master, to write my thesis about this project, is something that I will cherish for a long time.

The process of writing my thesis has confirmed me once again that I want to pursue a career in the energy transition. There are great challenges ahead of humankind to combat climate change and I am highly motivated to contribute to that to the best of my abilities.

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Appendix A: Overview of regions per node

Netherlands		
	30NL	Entire country
Belgium		
	28BE	Entire country
Luxembourg		
	29LU	Entire country
Ireland		
	96IE	Entire country
Great Britain		
	90UK	Regions South-East, London & Eastern
	91UK	Regions South-West
	92UK	Regions Wales, West Midlands & East Midlands
	93UK	Regions North-East, North-West & Yorkshire and Humberside
	94UK	Scotland
	95UK	Northern-Ireland
Denmark		
	38DK	Syddanmark, Midtjylland & Nordjylland
	42DK	Hovedstaden & Sjælland
Germany		
	31DE	States Schleswig-Holstein (+ Hamburg), Niedersachsen (+ Bremen) & Sachsen-Anhalt
	32DE	States Mecklenburg-Vorpommern & Brandenburg (+ Berlin)
	33DE	States Nordrhein-Westfalen
	34DE	States Sachsen & Thüringen
	35DE	States Saarland, Rheinland-Pfalz & Hessen
	36DE	State Baden-Württemberg
	37DE	State Bayern
France		
	14FR	Cantons Aquitaine & Midi-Pyrenees
	15FR	Cantons Languedoc-Roussillon
	16FR	Canton Provence-Alpes-Côte d’Azur
	17FR	Cantons Pays de la Loire & Poitou-Charentes
	18FR	Canton Centre-Val-de-Loire & Limousin
	19FR	Canton Auvergne
	20FR	Cantons Rhone-Alpes
	21FR	Canton Bretagne
	22FR	Canton Basse-Normandie
	23FR	Canton Ile-de-France
	24FR	Cantons Bourgogne
	25FR	Cantons Lorraine, Alsace, Franche-Comté,
	26FR	Cantons Calais, Picardie, Haute-Normandie
	27FR	Cantons Champagne-Ardenne

Sweden

86SE	Provinces Norrbotten
87SE	Provinces Västerbotten, Västernorrland, Jämtland & Gävleborg
88SE	Provinces Stockholm, Uppsala, Södermanland, Östergötland, Jönköping, Kalmar, Gotland, Västra, Götaland, Värmland, Örebro, Västmanland & Dalarna
89SE	Province Skane, Halland, Kronoberg & Blekinge

Norway

79NO	Province Aust-Agder, Vest-Agder & Rogaland
80NO	Province Buskerud, Vestfold & Telemark
81NO	Province Hordaland & Sogn og Fjordane
82NO	Province Ostfold, Akershus, Oslo, Hedmark & Oppland
83NO	Province More og Romsdal & Sor-Trondelag
84NO	Province Troms, Norland & Nord-Trondelag
85NO	Province Finnmark

Appendix B: Sources of allocation hydrogen demand

Allocation of hydrogen demand for the industrial sector	
European allocation	
Indicator	Industrial GDP for Industry, including energy (ISIC rev4)
Measure	US Dollars (CPC: Current prices, current PPPs)
Year of data	2018
Source	OECD Stats
URL:	https://stats.oecd.org/index.aspx?queryid=60702
Allocation of Germany	
Indicator	Turnover in the industrial sector
Measure	Billions of euros
Year of data	2018
Source	Deutschland in Zahlen
URL:	https://www.deutschlandinzahlen.de/tab/bundeslaender/branchen-unternehmen/industrie/umsaetze-in-der-industrie
Allocation of France	
Indicator	Energy consumption in the industrial sector
Measure	Thousands of oil-equiv. (BOE)
Year of data	2018
Source	Insee
URL:	https://www.insee.fr/fr/statistiques/4316155?sommaire=4316157
Allocation of United Kingdom	
Indicator	Final Energy Consumption in Industrial & Commercial sector
Measure	Thousands of oil-equiv. (BOE)
Year of data	2017
Source	Department for Business, Energy & Industrial Strategy
URL:	https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/833987/Sub-national-total-final-energy-consumption-statistics_2005-2017.xlsx
Allocation of Norway	
Indicator	Final Energy Consumption in Industrial
Measure	GWh
Year of data	2018
Source	Statistisk sentralbyra
URL:	https://www.ssb.no/energi-og-industri/statistikker/elektrisitet/aar
Allocation of Sweden	
Indicator	Energy consumption in the industrial sector
Measure	MWh
Year of data	2018
Source	SCB
URL:	http://www.statistikdatabasen.scb.se/pxweb/en/ssd/START__EN__EN0203/SlutAnvSektor/table/tableViewLayout1/

Allocation of Denmark	
Indicator	Energy consumption of industry
Measure	Thousands of Gigajoules
Year of data	2018
Source	Statbank
URL:	https://www.statbank.dk/10211

Allocation of hydrogen demand for the mobility sector	
European allocation	
Indicator	Transport - Transport Measurement - Freight Transport - Road freight transport
Measure	Tonnes-kilometres, Millions
Year of data	2015
Source	OECD Stats
URL:	https://stats.oecd.org/index.aspx?queryid=60702
Allocation of Germany	
Indicator	Goods transported
Measure	Thousands of tons
Year of data	2018
Source	Statistische Ämter des Bundes und der Länder Gemeinsames Statistikportal
URL:	https://www.statistikportal.de/de/transport-und-verkehr/eisenbahnverkehr
Allocation of France	
Indicator	Amount of enterprises in logistics and storage sector
Measure	Numbers of enterprises
Year of data	2018
Source	Insee
URL:	https://www.insee.fr/fr/statistiques/2012728
Allocation of United Kingdom	
Indicator	Road transport energy consumption
Measure	Tons of oil equivalent (BOE)
Year of data	2017
Source	Department for Business, Energy & Industrial Strategy
URL:	https://www.gov.uk/government/statistical-data-sets/road-transport-energy-consumption-at-regional-and-local-authority-level
Allocation of Norway	
Indicator	Goods transported from region of loading
Measure	Thousands of tons
Year of data	2015
Source	Statistisk sentralbyra
URL:	https://www.ssb.no/statbank/table/07394/tableViewLayout1/

Allocation of Sweden	
Indicator	Average distance driven of trucks
Measure	Scandinavian miles (=10km)
Year of data	2018
Source	SCB
URL:	http://www.statistikdatabasen.scb.se/pxweb/en/ssd/START__EN__EN0203/SlutAnvSektor/table/tableViewLayout1/
Allocation of Denmark	
Indicator	Goods transported from region of loading
Measure	Thousands of tons
Year of data	2015
Source	Statbank
URL:	https://www.statbank.dk/10211

APPENDIX C: SOURCES OF PROPERTIES POWER PLANTS

Data	Objective	Reference
Technical properties	Power & conversion plants (Nuclear, Gas & CCS, Biomass, offshore wind, onshore wind, PV)	(IEA, 2016) (IEA, 2019) (Navigant, 2020)
Investment costs & fixOPEX		(IEA, 2016) (IEA, 2019) (Navigant, 2020)
Fuel prices		(TYNDP2018 Executive Report, 2018)
Generation capacity in EU		(1.5 TECH Scenario - EC, 2018)
Generation capacity in Norway		(TYNDP2018 Executive Report, 2018)
Allocation of generation capacities per country		(TYNDP2018 Executive Report, 2018)
Allocation of generation capacities per country	Hydropower plants	(e-Highway2050, 2015)
Generation profiles		(ENTSOE, 2019)
Capacity factors	Renewable power plants (offshore wind, onshore wind, PV)	(IEA, 2015)
Technical properties	Battery storage	(IRENA, 2017)
Investment costs & fixOPEX		(IRENA, 2017)
Storage capacity per node		(1.5 TECH Scenario - EC, 2018)
Technical properties	Pumped hydro storage	(IRENA, 2017)
Investment costs & fixOPEX		(IRENA, 2017)
Storage capacity per node		(e-Highway2050, 2015)
Technical properties	Hydrogen storage (salt caverns)	(Caglayan, et al., 2020)
Investment costs & fixOPEX		(Gas for Climate, 2020)
Storage capacity per node		(Caglayan, et al., 2020)
Investment costs & fixOPEX	Hydrogen imports	(Gas for Climate, 2020)
Import prices		(Gas for Climate, 2020)
Investment costs & fixOPEX	Electricity transmission	(Navigant, 2020)
Cross-border capacities		(TYNDP2018 Executive Report, 2018)
Investment costs & fixOPEX	Hydrogen transmission	(Gas for Climate, 2020)
Cross-border capacities		(TYNDP2018 Capacities, 2019)
Electricity demand EU	Electricity demand	(1.5 TECH Scenario - EC, 2018)
Electricity demand Norway		(TYNDP2018 Executive Report, 2018)
Allocation of electricity demand over nodes		(TYNDP2018 Executive Report, 2018)
Hydrogen hourly load per node	Hydrogen demand	See Appendix B

APPENDIX D: CAPACITIES OF POWER PLANTS PER NODE

Node	PV		Onshore wind		Offshore wind		Hydropower
	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)
14_FR	7714	3857	3350	1675	0	9800	2095
15_FR	6581	3290	3509	1754	0	0	5309
16_FR	7190	3595	3149	1575	0	0	2695
17_FR	3223	1611	6416	3208	7318	1428	13
18_FR	3985	1993	5125	2563	0	0	424
19_FR	4030	2015	2201	1100	0	0	3779
20_FR	6879	3440	1194	597	0	0	6345
21_FR	115	57	8378	4189	7903	0	236
22_FR	759	379	4589	2294	2459	0	7
23_FR	4341	2170	2459	1229	0	0	45
24_FR	1676	838	1871	936	0	0	34
25_FR	3037	1519	2996	1498	0	0	1343
26_FR	1487	744	7319	3660	11592	0	2
27_FR	534	267	1026	513	0	0	607
28_BE	19487	9744	8462	4231	12148	0	322
29_LU	951	476	275	137	0	0	148
30_NL	40747	20373	8132	4066	10879	0	18
31_DE	18876	9438	29231	14616	29038	0	192
32_DE	13095	6548	23872	11936	9.894	0	0
33_DE	13964	6982	11435	5718	0	0	107
34_DE	17144	8572	13409	6704	0	0	59
35_DE	13752	6876	6030	3015	0	0	18
36_DE	14501	7250	2014	1007	0	0	916
37_DE	33564	16782	3630	1815	0	0	2874
38_DK	4565	2282	5832	2916	2285	1305	4
72_DK	2037	1019	2058	1029	2285	1305	0
79_NO	347	173	1262	631	400	7000	10106
80_NO	360	180	1500	750	0	0	6890
81_NO	345	173	935	467	0	7400	10356
82_NO	382	191	2631	1316	0	7400	4921
83_NO	373	186	1409	705	0	7400	3132
84_NO	856	428	1558	779	0	7400	5621
85_NO	338	169	741	370	0	0	398
86_SE	2619	1310	3229	1615	0	1400	5712
87_SE	1926	963	3720	1860	0	1400	8900
88_SE	1119	559	9542	4771	0	8500	3108
89_SE	273	137	2651	1325	1908	6592	735
90_UK	7233	3616	4778	2389	6852	4598	18
91_UK	8858	4429	3056	1528	0	0	1
92_UK	9276	4638	6996	3498	5847	0	1801
93_UK	6150	3075	2733	1367	5559	0	102
94_UK	2832	1416	2955	1478	960	0	1438
95_UK	198	99	1351	676	0	0	0
96_IE	1772	886	7143	3572	3220	18980	171
99_FR	1596	798	322	161	0	0	0
01_UK	0	0	0	0	15221	11679	0
02_UK	0	0	0	0	7025	22259	0
01_NL	0	0	0	0	14.636	6851	0
02_NL	0	0	0	0	8.782	12705	0
01_DE	0	0	0	0	10.538	0	0
01_DK	0	0	0	0	6856	6994	0

Remarks:
- The ‘Added Potential’ for PV and Onshore Wind are added from Scenario 1.1
- The ‘Added Potential’ for PV and Onshore Wind are added from Scenario 1.2

Node	**Nuclear**	**Gas & CCS**	**Biomass**	**P2G**		**OCGT**		**CCGT**	
	Old Capacity (MW)	Old Capacity (MW)	Old Capacity (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)
14_FR	2661	0	323	0	1000000	0	1000000	0	1000000
15_FR	0	0	215	0	1000000	0	1000000	0	1000000
16_FR	1996	620	108	0	1000000	0	1000000	0	1000000
17_FR	2661	0	323	0	1000000	0	1000000	0	1000000
18_FR	3327	194	431	0	1000000	0	1000000	0	1000000
19_FR	4657	0	108	0	1000000	0	1000000	0	1000000
20_FR	0	0	108	0	1000000	0	1000000	0	1000000
21_FR	0	116	108	0	1000000	0	1000000	0	1000000
22_FR	1996	77	108	0	1000000	0	1000000	0	1000000
23_FR	1331	155	215	0	1000000	0	1000000	0	1000000
24_FR	0	0	215	0	1000000	0	1000000	0	1000000
25_FR	3327	736	215	0	1000000	0	1000000	0	1000000
26_FR	6653	658	323	0	1000000	0	1000000	0	1000000
27_FR	1331	0	108	0	1000000	0	1000000	0	1000000
28_BE	0	1424	1057	0	1000000	0	1000000	0	1000000
29_LU	0	0	42	0	1000000	0	1000000	0	1000000
30_NL	0	4687	0	0	1000000	0	1000000	0	1000000
31_DE	0	3464	0	0	1000000	0	1000000	0	1000000
32_DE	0	2787	0	0	1000000	0	1000000	0	1000000
33_DE	0	6731	0	0	1000000	0	1000000	0	1000000
34_DE	0	1428	0	0	1000000	0	1000000	0	1000000
35_DE	0	1279	0	0	1000000	0	1000000	0	1000000
36_DE	0	1344	0	0	1000000	0	1000000	0	1000000
37_DE	0	2282	0	0	1000000	0	1000000	0	1000000
38_DK	0	0	1017	0	1000000	0	1000000	0	1000000
72_DK	0	0	509	0	1000000	0	1000000	0	1000000
79_NO	0	0	0	0	1000000	0	1000000	0	1000000
80_NO	0	0	76	0	1000000	0	1000000	0	1000000
81_NO	0	0	0	0	1000000	0	1000000	0	1000000
82_NO	0	0	0	0	1000000	0	1000000	0	1000000
83_NO	0	0	0	0	1000000	0	1000000	0	1000000
84_NO	0	0	0	0	1000000	0	1000000	0	1000000
85_NO	0	0	0	0	1000000	0	1000000	0	1000000
86_SE	0	0	287	0	1000000	0	1000000	0	1000000
87_SE	0	0	2008	0	1000000	0	1000000	0	1000000
88_SE	2197	0	861	0	1000000	0	1000000	0	1000000
89_SE	732	0	287	0	1000000	0	1000000	0	1000000
90_UK	848	2819	2593	0	1000000	0	1000000	0	1000000
91_UK	1413	1306	0	0	1000000	0	1000000	0	1000000
92_UK	565	2544	1852	0	1000000	0	1000000	0	1000000
93_UK	1413	619	1111	0	1000000	0	1000000	0	1000000
94_UK	283	1031	1111	0	1000000	0	1000000	0	1000000
95_UK	0	688	0	0	1000000	0	1000000	0	1000000
96_IE	0	1113	283	0	1000000	0	1000000	0	1000000
01_UK	0	0	0	0	0	0	0	0	0
02_UK	0	0	0	0	0	0	0	0	0
01_NL	0	0	0	0	0	0	0	0	0
02_NL	0	0	0	0	0	0	0	0	0
01_DE	0	0	0	0	0	0	0	0	0
01_DK	0	0	0	0	0	0	0	0	0

Appendix E: Capacities of storage plants per node

Node	Battery_2		Battery_4		Battery_6	
	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)
14_FR	0	1000000	798	0	0	1000000
15_FR	0	1000000	478	0	0	1000000
16_FR	0	1000000	816	0	0	1000000
17_FR	0	1000000	640	0	0	1000000
18_FR	0	1000000	522	0	0	1000000
19_FR	0	1000000	521	0	0	1000000
20_FR	0	1000000	499	0	0	1000000
21_FR	0	1000000	713	0	0	1000000
22_FR	0	1000000	290	0	0	1000000
23_FR	0	1000000	1743	0	0	1000000
24_FR	0	1000000	265	0	0	1000000
25_FR	0	1000000	722	0	0	1000000
26_FR	0	1000000	1008	0	0	1000000
27_FR	0	1000000	115	0	0	1000000
28_BE	0	1000000	1793	0	0	1000000
29_LU	0	1000000	162	0	0	1000000
30_NL	0	1000000	2678	0	0	1000000
31_DE	0	1000000	1892	0	0	1000000
32_DE	0	1000000	1072	0	0	1000000
33_DE	0	1000000	2463	0	0	1000000
34_DE	0	1000000	1068	0	0	1000000
35_DE	0	1000000	1527	0	0	1000000
36_DE	0	1000000	1498	0	0	1000000
37_DE	0	1000000	1787	0	0	1000000
38_DK	0	1000000	572	0	0	1000000
72_DK	0	1000000	478	0	0	1000000
79_NO	0	1000000	376	0	0	1000000
80_NO	0	1000000	338	0	0	1000000
81_NO	0	1000000	299	0	0	1000000
82_NO	0	1000000	939	0	0	1000000
83_NO	0	1000000	279	0	0	1000000
84_NO	0	1000000	258	0	0	1000000
85_NO	0	1000000	35	0	0	1000000
86_SE	0	1000000	85	0	0	1000000
87_SE	0	1000000	255	0	0	1000000
88_SE	0	1000000	1928	0	0	1000000
89_SE	0	1000000	567	0	0	1000000
90_UK	0	1000000	2549	0	0	1000000
91_UK	0	1000000	620	0	0	1000000
92_UK	0	1000000	2480	0	0	1000000
93_UK	0	1000000	689	0	0	1000000
94_UK	0	1000000	344	0	0	1000000
95_UK	0	1000000	207	0	0	1000000
96_IE	0	1000000	798	0	0	1000000
99_FR	0	0	48	0	0	0
01_UK	0	0	0	0	0	0
02_UK	0	0	0	0	0	0
01_NL	0	0	0	0	0	0
02_NL	0	0	0	0	0	0
01_DE	0	0	0	0	0	0
01_DK	0	0	0	0	0	0

Node	Pump		Pump_67		Pump_190		H2 Salt caverns	
	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)
14_FR	0	0	746	0	0	0	0	0
15_FR	0	0	1688	0	0	0	0	0
16_FR	0	0	810	0	0	0	0	0
17_FR	0	0	0	0	0	0	0	0
18_FR	0	0	144	0	0	0	0	0
19_FR	0	0	1660	0	0	0	0	0
20_FR	0	0	3012	0	700	0	0	0
21_FR	78	0	0	0	0	0	0	0
22_FR	0	0	0	0	0	0	0	0
23_FR	0	0	0	0	0	0	0	0
24_FR	0	0	0	0	0	0	0	0
25_FR	0	0	0	0	700	0	0	0
26_FR	0	0	0	0	0	0	0	0
27_FR	0	0	349	0	0	0	0	0
28_BE	0	0	1308	0	0	0	0	0
29_LU	0	0	1044	0	0	0	0	0
30_NL	0	0	0	0	0	0	0	336000
31_DE	0	0	517	0	0	0	0	3150000
32_DE	0	0	11	0	0	0	0	0
33_DE	0	0	731	0	0	0	0	3150000
34_DE	0	0	2809	0	0	0	0	3150000
35_DE	0	0	687	0	0	0	0	0
36_DE	0	0	2738	0	4969	0	0	0
37_DE	0	0	601	0	2653	0	0	3150000
38_DK	0	0	0	0	0	0	0	1820000
72_DK	0	0	0	0	0	0	0	0
79_NO	0	0	2668	0	0	0	0	0
80_NO	0	0	1819	0	0	0	0	0
81_NO	0	0	2734	0	0	0	0	0
82_NO	0	0	1299	0	0	0	0	0
83_NO	0	0	827	0	0	0	0	0
84_NO	0	0	1484	0	0	0	0	0
85_NO	0	0	105	0	0	0	0	0
86_SE	0	0	0	0	0	0	0	0
87_SE	0	0	0	0	0	0	0	0
88_SE	0	0	0	0	0	0	0	0
89_SE	0	0	0	0	0	0	0	0
90_UK	0	0	22	0	0	0	0	0
91_UK	0	0	1	0	0	0	0	0
92_UK	0	0	2169	0	0	0	0	1680000
93_UK	0	0	123	0	0	0	0	1680000
94_UK	0	0	1731	0	0	0	0	0
95_UK	0	0	0	0	0	0	0	0
96_IE	0	0	1206	0	0	0	0	0
99_FR	0	0	0	0	0	0	0	0
01_UK	0	0	0	0	0	0	0	0
02_UK	0	0	0	0	0	0	0	0
01_NL	0	0	0	0	0	0	0	0
02_NL	0	0	0	0	0	0	0	0
01_DE	0	0	0	0	0	0	0	0
01_DK	0	0	0	0	0	0	0	0

Appendix F: Transmission capacities

Node	Node	Length (km)	Electricity		Hydrogen	
			Old Capacity (MW)	Added Potential (MW)	Old Capacity (MW)	Added Potential (MW)
14_FR	15_FR	189	1000000	0	1000000	0
15_FR	16_FR	254	1000000	0	1000000	0
14_FR	17_FR	308	1000000	0	1000000	0
14_FR	18_FR	360	1000000	0	1000000	0
15_FR	18_FR	306	1000000	0	1000000	0
17_FR	18_FR	190	1000000	0	1000000	0
16_FR	19_FR	173	1000000	0	1000000	0
18_FR	19_FR	257	1000000	0	1000000	0
16_FR	20_FR	237	1000000	0	1000000	0
19_FR	20_FR	136	1000000	0	1000000	0
17_FR	21_FR	244	1000000	0	1000000	0
17_FR	22_FR	248	1000000	0	1000000	0
21_FR	22_FR	211	1000000	0	1000000	0
18_FR	23_FR	191	1000000	0	1000000	0
22_FR	23_FR	184	1000000	0	1000000	0
18_FR	24_FR	181	1000000	0	1000000	0
19_FR	24_FR	272	1000000	0	1000000	0
20_FR	24_FR	205	1000000	0	1000000	0
23_FR	24_FR	196	1000000	0	1000000	0
20_FR	25_FR	266	1000000	0	1000000	0
24_FR	25_FR	306	1000000	0	1000000	0
22_FR	26_FR	169	1000000	0	1000000	0
23_FR	26_FR	216	1000000	0	1000000	0
23_FR	27_FR	147	1000000	0	1000000	0
25_FR	27_FR	167	1000000	0	1000000	0
26_FR	27_FR	179	1000000	0	1000000	0
25_FR	28_BE	159	374	3026	0	0
26_FR	28_BE	287	2711	946	37333	1000000
27_FR	28_BE	175	1215	424	0	0
81_NO	28_BE	160	0	0	16267	1000000
28_BE	29_LU	152	680	500	1627	1000000
28_BE	30_NL	191	3400	10100	60994	1000000
30_NL	31_DE	271	824	576	35960	1000000
31_DE	32_DE	228	1000000	0	1000000	0
28_BE	33_DE	223	1000	5000	0	0
30_NL	33_DE	162	4176	2923	32335	1000000
31_DE	33_DE	219	1000000	0	1000000	0
32_DE	34_DE	208	1000000	0	1000000	0
25_FR	35_DE	246	2423	4677	20190	1000000
28_BE	35_DE	162	0	0	20428	1000000
29_LU	35_DE	333	2300	2000	1280	1000000
31_DE	35_DE	147	1000000	0	1000000	0
33_DE	35_DE	312	1000000	0	1000000	0
34_DE	35_DE	195	1000000	0	1000000	0
25_FR	36_DE	510	2077	138	0	0
35_DE	36_DE	344	1000000	0	1000000	0
34_DE	37_DE	197	1000000	0	1000000	0
35_DE	37_DE	488	1000000	0	1000000	0
36_DE	37_DE	260	1000000	0	1000000	0
30_NL	38_DK	274	700	0	0	0
31_DE	38_DK	181	3500	2500	8583	1000000
32_DE	72_DK	499	600	0	0	0
38_DK	72_DK	333	1000000	0	1000000	0

26_FR	79_NO	270	0	0	19000	1000000
30_NL	79_NO	172	700	18000	32122	1000000
31_DE	79_NO	739	1400	13000	72880	1000000
38_DK	79_NO	652	1700	940	0	0
79_NO	80_NO	335	1000000	0	1000000	0
79_NO	81_NO	152	1000000	0	1000000	0
80_NO	81_NO	216	1000000	0	1000000	0
94_UK	81_NO	143	0	0	23527	1000000
80_NO	82_NO	172	1000000	0	1000000	0
81_NO	83_NO	283	1000000	0	1000000	0
82_NO	83_NO	188	1000000	0	1000000	0
83_NO	84_NO	488	1000000	0	1000000	0
84_NO	85_NO	497	1000000	0	1000000	0
84_NO	86_SE	234	631	85	0	0
83_NO	87_SE	316	902	122	0	0
84_NO	87_SE	363	225	31	0	0
86_SE	87_SE	407	1000000	0	1000000	0
38_DK	88_SE	465	740	303	0	0
82_NO	88_SE	323	1937	262	0	0
87_SE	88_SE	499	1000000	0	1000000	0
31_DE	89_SE	474	1315	3885	0	0
32_DE	89_SE	386	0	15000	0	0
72_DK	89_SE	168	1700	696	5550	1000000
88_SE	89_SE	307	1000000	0	1000000	0
22_FR	90_UK	313	2300	8700	0	0
26_FR	90_UK	275	4600	10400	0	0
28_BE	90_UK	353	1000	6000	48503	1000000
30_NL	90_UK	390	1000	1000	16467	1000000
81_NO	90_UK	1066	0	2000	0	0
90_UK	91_UK	232	1000000	0	1000000	0
31_DE	92_UK	727	1400	0	0	0
38_DK	92_UK	804	1400	0	0	0
79_NO	92_UK	902	0	5000	0	0
90_UK	92_UK	196	1000000	0	1000000	0
91_UK	92_UK	204	1000000	0	1000000	0
79_NO	93_UK	719	1400	0	0	0
92_UK	93_UK	239	1000000	0	1000000	0
93_UK	94_UK	273	1000000	0	1000000	0
93_UK	95_UK	287	1000000	0	1000000	0
21_FR	96_IE	682	0	7700	0	0
92_UK	96_IE	385	531	1969	0	0
93_UK	96_IE	188	0	0	30713	1000000
95_UK	96_IE	737	1169	1931	1400	1000000
81_NO	01_UK	388	0	1000000	0	0
92_UK	01_UK	366	0	1000000	0	0
93_UK	01_UK	191	0	1000000	0	0
90_UK	02_UK	315	0	1000000	0	0
92_UK	02_UK	244	0	1000000	0	0
30_NL	01_NL	799	0	1000000	0	0
81_NO	01_NL	112	0	1000000	0	0
01_UK	01_NL	96	0	1000000	0	0
30_NL	02_NL	91	0	1000000	0	0
02_UK	02_NL	217	0	1000000	0	0
31_DE	01_DE	478	0	1000000	0	0
32_DE	01_DE	328	0	1000000	0	0
33_DE	01_DE	498	0	1000000	0	0
79_NO	01_DE	158	0	1000000	0	0
01_NL	01_DE	168	0	1000000	0	0
38_DK	01_DK	87	0	1000000	0	0

01_DE	01_DK	450	0	1000000	0	0
94_UK	81_NO	486	0	0	26443	1000000