The role of green hydrogen in Belgium's future energy system

Master thesis

by

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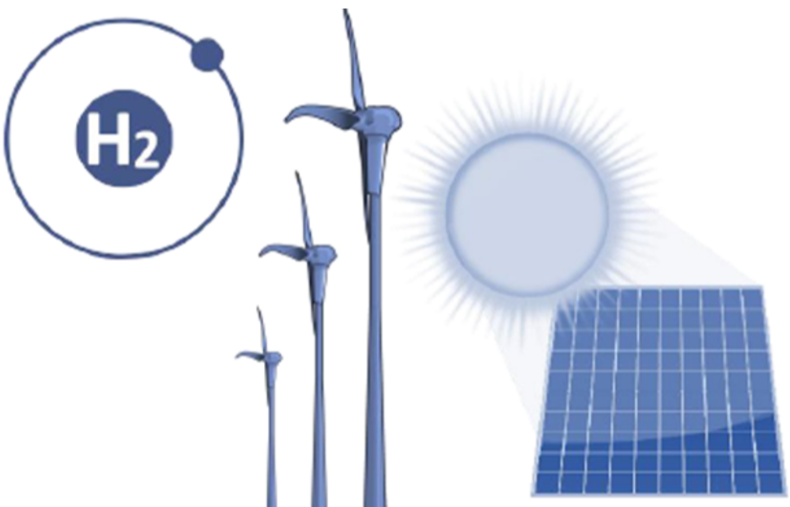
June 2018



MSc. Sustainable Energy Planning and Management
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Master thesis:

The role of green hydrogen in Belgium's future energy system

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Abstract

Contrary to the pursued drastic decrease in greenhouse gas emissions towards 2050, in Belgium, various sectors are still dominated by fossil fuels such as transport and industry, that need alternatives provided by upcoming technologies. As such, The Belgian industry has a large use of fossil-based hydrogen ('grey hydrogen'). Most progress has been made in the electricity sector with increasing amounts of renewable energy sources (RES). However, the intermittent character of solar and wind power and the specific location (cf. offshore wind) entails challenges as well: grid imbalances due to periods of extremely low or high RES generation, and grid connection issues.

With the aim to find a solution to these issues, *the future role of green hydrogen in the Belgian energy system* is the subject of this research. Electricity from renewables can be converted into hydrogen through electrolysis resulting in a green and valuable gas.

First, the green hydrogen demand in 2050 is forecasted in different sectors (industry, transport and heating). The total demand is estimated 55 TWh or 1660 kton of hydrogen. The largest demand is found in the transport sector, followed by industry.

This demand is the starting point of the design of a hydrogen production system. The system is connected to an offshore wind farm and two scenarios are compared that differ in the way of bringing offshore wind energy ashore: (1) an electric grid with onshore electrolysis and (2) offshore electrolysis where hydrogen is transported ashore via existing gas pipelines. A 22 GW electrolyser and a 24.5 GW wind farm are the cost-optimal dimensions that meet the hydrogen demand. The electrolyser uses its entire capacity for 43% of the time as it is dependent on intermittent offshore wind power.

A socio-economic analysis shows that onshore electrolysis has a lower levelised cost of hydrogen (LCOH) than offshore electrolysis, mainly because of the high additional costs for operating offshore. The LCOH of the onshore scenarios is estimated 4.5 €/kg, compared to the offshore LCOH of 5.2 €/kg. However, in neither scenario, the green hydrogen produced will be competitive with grey hydrogen (2.88 €/kg). The electricity cost is clearly the dominating element in the LCOH.

The third part focuses on the role of green hydrogen in grid-balancing, in a 2050 RES electricity scenario for Belgium. Large excesses and deficits, often lasting for longer periods, are observed that can be dealt with by hydrogen long-term storage. Opportunities arise since excesses often coincide with low or negative prices, and residual load with high prices. Hydrogen storage is expected to be economically feasible since hydrogen production at negative prices drives down the cost. However, electricity prices contain much uncertainty and in general, it is concluded that a large spread between the electricity prices when consuming and reinjecting is required.

Finally, the energy systems for demand and storage purposes are coupled by using the electrolyser in the onshore scenario for grid-balancing purposes as well. The integrated system has a lower system cost, even though the difference is rather small.

Preface

This thesis report is composed in the time period between February and June 2018 by a student at Aalborg University as a part of the Master Program in Sustainable Energy Planning and Management. The research topic of the report has been developed in joint consultation with Elia, Belgium's transmission system operator (TSO). The interest in green hydrogen arose from the student's belief in 100% renewable energy systems, combined with Elia's interest in identifying both challenges and opportunities towards the future energy systems from a TSO's viewpoint. Next to its core activities as a TSO, one of Elia's strategy building blocks is to *keep the eyes wide open on innovation and M&A*. Elia is preparing the company for the future by looking for innovation and growth opportunities. In this context, power-to-gas fits in the aimed intersectoral coupling and greening of society.

I would like to address great thanks to the supervisor of this project, *Poul Alberg Østergaard*, for the inspiring supervision and constructive criticism during the project period. Besides, I would also like to thank Elia, and *Yannick Schuermans* more specifically for sharing a thorough understanding of Belgium's electricity system as well as providing additional advice and the required data. Lastly, I am grateful to my family and friends for their mental support and proof-reading efforts.

Reading guide

Through the report source references in the form of the Harvard method will appear and these are all listed alphabetically at the end of the report. References from books, homepages or the like will appear with the last name of the author and the year of publication in the form of [Author, Year].

Figures and tables in the report are numbered according to the respective chapter. In this way the first figure in chapter 2 has number 2.1, the second number 2.2 etc. Explanatory text is found under the given figures and tables. Figures without references are composed by the project author.

I wish you a very pleasant reading!

Emilie Gysels

Nomenclature

AC	Alternating current
BEV	Battery electric vehicle
$CAES$	Compressed air energy storage
$CAPEX$	Capital expenses
$CCGT$	Closed cycle gas turbine
CNG	Compressed natural gas
CO_2	Carbon dioxide
DC	Direct current
DSM	Demand-side management
DSO	Distribution System Operator
ETS	Emission trading system
EU	European Union
EUR	Euro
EV	Electric vehicle
$FCEV$	Fuell cell electric vehicle
GHG	Greenhouse gas
GoO	Guarantee of Origin
H_2	Hydrogen
HHV	Higher heating value
HV	High voltage
$IPCC$	Intergovernmental Panel on Climate Change
$LCOE$	Levelised cost of electricity
$LCOH$	Levelised cost of hydrogen
LHV	Lower heating value
MLP	Multi-level perspective
NG	Natural gas
$O\&M$	Operation and maintenance
$OCGT$	Open cycle gas turbine
$OPEX$	Operational expenses
$PHES$	Pumped hydro energy storage
PV	Photovoltaic
RE	Renewable energy
RES	Renewable energy sources
TEP	Transmission expansion planning
TSO	Transmission system operator
VAT	Value added tax
$VREG$	Vlaamse Regulator voor Electriciteit en Gas (Flemish Regulator for Electricity and Gas

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1 Introduction

Initiated by the energy transition, many technologies have found their way towards visions and narratives about the future energy system. Power-to-gas is one of them. Power-to-gas refers to the conversion from electricity into gas by means of electrolysis, a chemical process where water is split into hydrogen and oxygen. The resulting molecule *hydrogen* is a valuable gaseous substance and can be used in a variety of applications, as a fuel or as feedstock.

Hydrogen is gaining ground as it can be produced from 100% renewable energy (RE). Tokyo has recently announced the aim of having a 'hydrogen society' by 2020 when the Olympic Games take place [Financial Times, 2018]. In Europe, more and more demonstration projects arise and the European Commission expresses the future importance of hydrogen [European Commission, 2017b]. Specifically for the North Sea, offshore wind energy is pointed out as a possible source of hydrogen production [World Energy Council Netherlands, 2017]. One of those countries by the North Sea is Belgium, where increasing investments in renewable energy sources (RES) may entail opportunities. RES indeed bring challenges as well, where hydrogen can offer a solution to.

The next chapter presents and explains three of those challenges which will eventually lead to the research question of this study. The problems arise from both locked-in fossil fuel based regimes as well as the consequences of the energy transition.

1.1 Need for decarbonisation

During the last few years, many climate records have been broken. The global average temperature keeps increasing, with rising sea levels as a consequence [World Meteo Organization, 2017]. The Paris Agreement of 2015 expressed the aim to keep the temperature increase below 1.5 degrees Celsius compared to pre-industrial levels. As the temperature level already reached a 1.1 degrees increase in 2016, action needs to be taken. In order to fight climate change, fossil fuels and the related greenhouse gas emissions (GHG) need to be phased out. [UNFCCC, 2016]

Belgium also committed to become carbon neutral by 2050 during the summit in Paris. The Belgian climate policy is mainly driven by European targets. However, as energy responsibilities are spread over the Federal Government and the three Regions[1], an energy pact between the different levels is to be made about the strategy towards 2050, where the

[1]Belgium is divided into three regions: the Flemish Region, the Brussels-Capital Region and the Walloon Region. Each region has its own government and parliament. The constitution defines which responsibilities are dealt with on the regional or federal level. For energy, the Federal Government deals with the transmission system, supply of oil and natural gas, pricing, offshore wind and nuclear power. The distribution system, RE, energy efficiency and RD are regional responsibilities. [Belgium.be, 2016]

shared efforts are formalised [ENOVER, 2017]. It was foreseen for 2015 but only in March 2018, an agreement was made. This agreement still leaves scope for interpretation with regard to the phase-out of nuclear energy, and the controversy among politicians about the topic continues[De Standaard, 2017a].

1.1.1 European GHG emissions and RES targets

The overall long-term aim of the European Union (EU) is to achieve a low-carbon economy by 2050. This implies a 80% reduction in GHG emissions. As part of this strategy, intermediary goals have been set for 2020 and 2030. For 2020, member states committed to the so called 20-20-20 objectives being a 20% cut in GHG emissions compared to 1990 levels, a 20% share of renewable energy (RE) and a 20% improvement in energy efficiency. Concerning RE, a specific target for transport has been set: 10% of the energy consumed in the transport sector (excl. aviation) is to be achieved from RES in 2020. [European Commission, 2018a] The target regarding the reduction in GHG emissions should also be more elaborated on. The overall goal of a 20% reduction comparing to 1990 levels is split into two 'subgoals' which are compared to 2005 levels. First, by means of the European Emission Trading System (EU ETS), a reduction of 21% is aimed in the period 2005-2020 [European Commission, 2018a]. The EU ETS creates a market where emissions can be traded and where a certain 'cap' or maximum level of allowed GHG emissions may decrease over time. The system applies to energy-intensive installations (power stations, industrial plants) and flights within Europe. Other sectors are not included in the EU ETS, being agriculture, housing, waste and transport (excl. aviation). A GHG emission reduction target of 10% (comparing to 2005) is set for those non-ETS sectors. [European Commission, 2018c]

By 2030, a 40% cut in GHG emissions (30% in non-ETS sectors) and 27% of RE is pursued [European Commission, 2018b].

In order to reach the overall EU goals, specific national targets are set for each member state according to its possibilities. Belgium committed to have a RE share of 13% and a 15% cut in non-ETS GHG emissions compared to 2005 levels by 2020. Notice that the RE share is lower and the GHG emissions cut is higher than the EU average. By 2030, Belgian non-ETS GHG emissions need to decrease by 35% but no RE target has been specified yet. With a RE share of 8.7% in 2016, Belgium is on track to reach its target [Federal Public Service Economy, SMEs, Self-employed and Energy, 2018a]. On the other hand, Belgium is likely to fail to meet its GHG emissions target. Prior to the climate summit in Bonn of 2017, the European Commission published a progress report reprimanding Belgium as Belgium is expected to miss its target by 3.5% in 2020. The report specifically points out the transport sector as the main culprit. [European Commission, 2017a]

1.1.2 Energy consumption in Belgium

As can be seen in Figure 1.1, the Belgian energy consumption is still dominated by fossil fuels. Of the primary energy consumption, 70% was represented by fossil fuels in 2016. This share is mostly coming from natural gas (NG) and oil consumption. A considerable share of nuclear energy can be noticed as well. A nuclear phase-out is planned by 2025 but however, as mentioned above, this might still be postponed as security of supply may not be guaranteed. The electricity consumption amounts for 17% of the total final energy consumption, while oil products and natural gas are again dominating. [Federal Public Service Economy, SMEs, Self-employed and Energy, 2018a]

Having closed its coal mines, Belgium does not dispose of any fossil primary resources which results in a high imports dependency. The share of net imports in the primary energy consumption amounted for 86% in 2016 [Federal Public Service Economy, SMEs, Self-employed and Energy, 2018a].

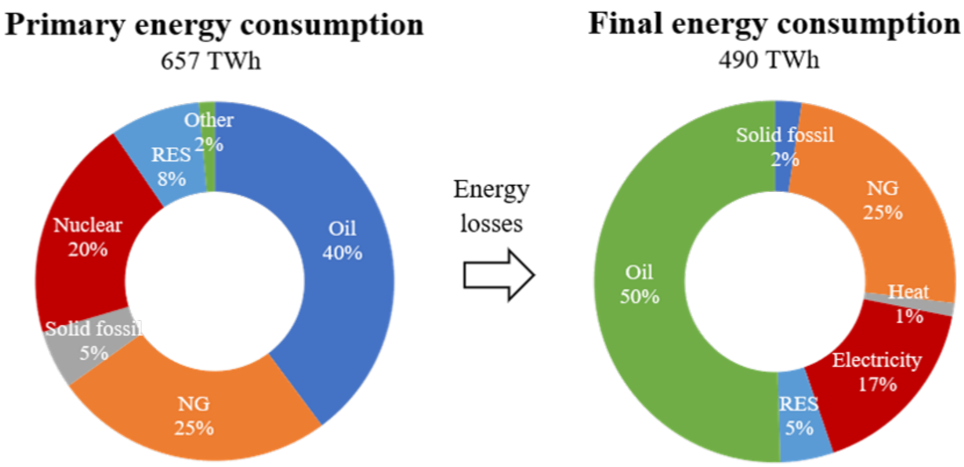

Figure 1.1: Primary and final energy consumption of Belgium in 2016 [Federal Public Service Economy, SMEs, Self-employed and Energy, 2018a]

1.1.3 GHG emissions

As Belgium is not on track to reach its emission targets, it is worth to look at which sectors are contributing the most to those GHG emissions. An overview is given in Figure 1.2. With a share of 28.3%, the industrial sector appears to be the biggest emitter. It is followed by the transport sector, buildings and the energy sector.

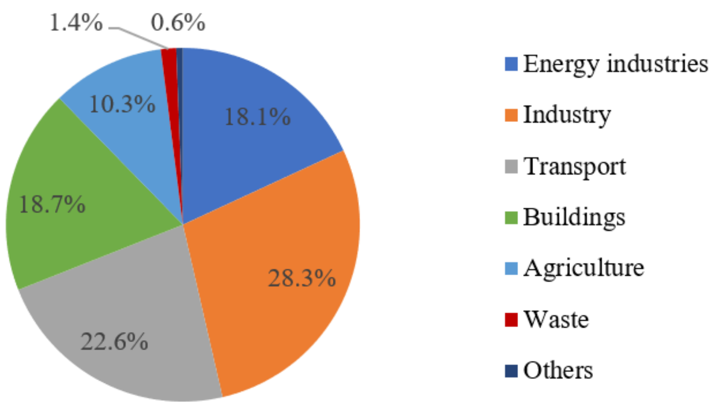

Figure 1.2: Belgian GHG emissions per sector [Federal Public Service Health, Food Chain Safety and Environment, 2017]

The high share of the industry sector can be explained by its still relatively important position in the Belgian economy, with a 15% share in the GDP. The chemical, food and metal industry are strongly anchored. Regarding emissions, the chemical industry is responsible for almost half of them. [Federal Public Service Health, Food Chain Safety and Environment, 2017]

One of the reasons of those emissions is the use of fossil hydrogen. Hydrogen is a product that is used daily in the industry. It can be used for the production of ammonia, in the petrochemical industry and the food industry. Nowadays, hydrogen is mostly produced through the reforming of natural gas by adding heat, called steam methane reforming (SMR). This can be called fossil or 'grey' hydrogen as it is a very carbon-intensive process. The mass of CO_2 emissions released when producing grey hydrogen is about ten times higher than the mass of the hydrogen produced [Jepma, 2017]. However, other cleaner technologies have been developed: 'blue' hydrogen being grey hydrogen where the CO_2 is captured and stored, and 'green' hydrogen that is produced through electrolysis from RE [World Energy Council Netherlands, 2017]. The greener alternatives are mature technologies but are in an early market stage, grey hydrogen is currently by far the most cost-effective. This has been proven by previous studies [WaterstofNet vzw, 2016]. In Table 1.1, a overview is given of the characteristics of both grey and green hydrogen.

	Energy input	**Efficiency**	**CO_2 emissions [g/MJ H_2]**	**Price (in 2015) [EUR/kg]**
Grey H_2 (SMR)	NG + electricity	70-85%	90	2-3 (large scale) 5-8 (tube trailer delivery)
Green H_2 (Electrolysis)	electricity	65-75%	0	4-5 (large-scale) 6.5-7.5 (small-scale)

Table 1.1: Characteristics of grey vs. green hydrogen

The contribution of the transport sector could be explained by the fact that Belgium has a very dense transport infrastructure, and it is a transit country for many trucks. On top of that, the road transport has experienced a constant growth. The result is an increasing saturation leading to a higher fuel consumption and consequently higher emissions. The car is the main mode for passenger transport. Cars and motorbikes represented 76% of motorised road mobility in 2015, next to public transport (16.3%) and railway (7.6%) [Federal Public Service Health, Food Chain Safety and Environment, 2017]. In 2016, 5.7 million passenger cars were counted compared to only 11 million inhabitants. Table 1.2 shows diesel and petrol cars are still largely dominating, complemented by a small share of alternatives where battery electric vehicles (BEVs), mainly hybrid BEVs, represent the biggest share. BEVs in total have experienced a growth of 43% from 2015 to 2016 [Febiac, 2017a]. Hydrogen-powered cars or fuel cell EVs (FCEVs) are not measured separately so one can assume this amount is very limited.

	Petrol	Diesel	LPG	Electric	Hybrid	CNG	Others
Number	2,239,107	3,338,351	15,561	5,194	48,539	4,161	18,851
Share	39.5%	58.9%	0.3%	0.1%	0.9%	0.1%	0.3%

Table 1.2: The Belgian car fleet divided by fuel in 2016 [Febiac, 2017a]

The third biggest emitter is the buildings sector where buildings mostly dispose of an individual heating system in Belgium [Federal Public Service Health, Food Chain Safety and Environment, 2017]. The main source for heating is natural gas with an estimated share of 55% (in 2010) [FPS Economy, SMEs, Self-employed and Energy, 2012].

1.2 Increasing RES

As part of the previously mentioned energy transition, the implementation of renewable energy sources (RES) has experienced a serious growth. Especially, the installed capacity of wind and photovoltaic (PV) power has been increasing and this trend is expected to continue. On the Belgian level, the PV installations have reached an installed capacity of 3.8 GW at the end of 2017 after a strong revival since 2016. The installed capacity of wind power grew with 465 MW in 2017 to a total capacity of 2.8 GW. 30% of this capacity is located offshore. [APERe, 2018] This rising trend is only expected to continue taking into account the ambitious goals and the continuously improving competitiveness. IRENA [2018] reported that electricity from RES will be cheaper than electricity from fossil fuels by 2020.

The increasing deployment of RE also engenders challenges. Wind and sun are both intermittent RES and are thus non-dispatchable. The sun is not always shining and the wind is not always blowing, or not at the moments when needed. Evolving to a low-carbon economy with 100% RE also corresponds to the phasing out of the more dispatchable fossil fuel-based technologies. In order to ensure a match between supply and demand in the future, additional measures will be indispensable. In the next two paragraphs, two specific challenges will be looked at more thoroughly, being the transport of offshore produced energy and grid-balancing needs.

1.2.1 Bringing electricity produced offshore to the mainland

The North Sea is seen as one of the main energy sources of RE for the surrounding countries by 2050. Its potential for wind energy gives it an important role in decarbonising the energy and feedstock supply. Together with onshore wind and PV, it is the fastest growing RES in the EU. The cost per electricity produced has also decreased rapidly over the last few years, with strikingly low bids in Denmark (49.9 €/kWh) and the Netherlands (54.5 €/kWh) making offshore wind energy a competitive option, not relying on high subsidies. Last year, even the world's first subsidy-free offshore wind farm was announced, to be placed in Germany. [WindEurope, 2017] [World Energy Council Netherlands, 2017]

The growth can also be noted in Belgium as well, where many offshore wind farms have been built and are to be built in the short-term. Figure 1.3 shows a map with the wind farms installed, under construction and planned by 2020. Currently, four wind farms with an installed capacity of 887 MW are operational. By 2020, five extra wind farms will be in place resulting in a total offshore capacity of 2292 MW corresponding to about 8.5 TWh per year or 10% of the Belgian electricity demand. [Belgian Offshore Platform, 2017]

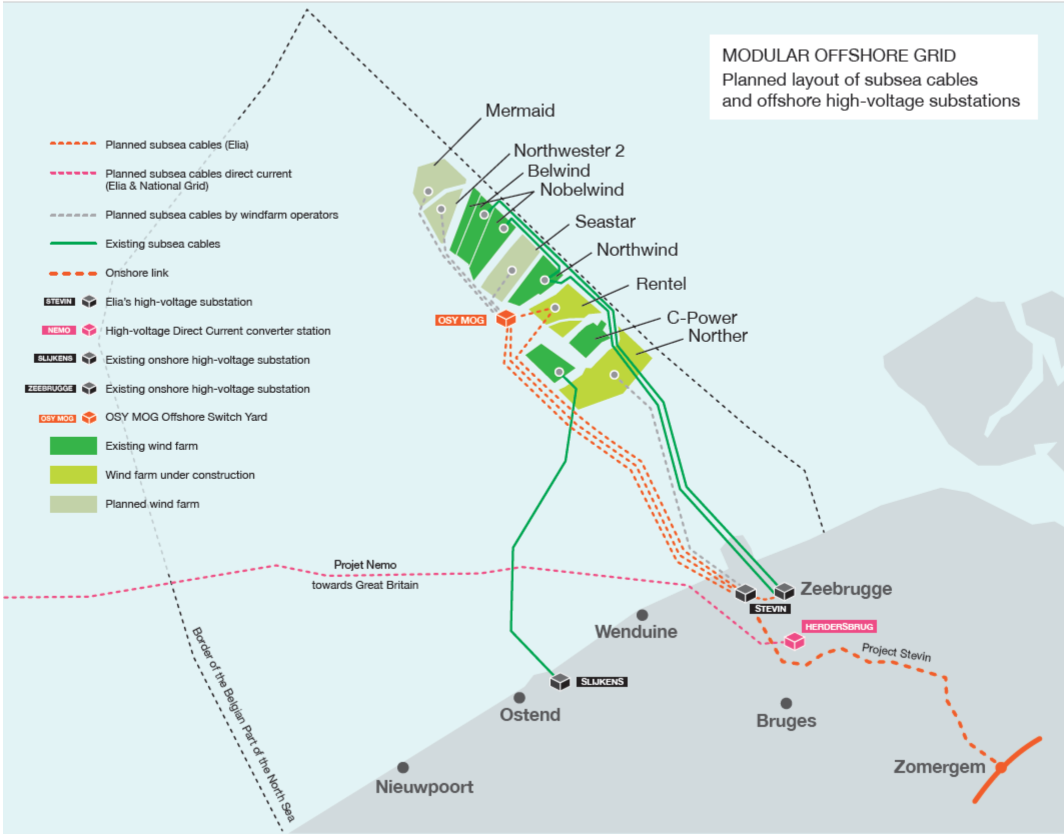

Figure 1.3: The design of the offshore modular grid in the North Sea [Elia, n/a]

Philippe De Backer, the Belgian State of Secretary of the North Sea, expressed the aim to have 4 GW of offshore wind power by 2026 for which a new zone will be developed. He also addressed space as a future issue because the Belgian marine territory is rather limited. It has an area of about 3500 km^2 which is only 0.5% of the total North Sea [Maes, 2016]. ICEDD [2013] estimated a potential of 8GW for the Belgian North Sea but further research in the framework of the Marine Spatial Plan 2020-2026 limits the potential to merely 4 GW [Secretary of State of the North Sea, 2017]. Philippe De Backer does not exclude that Belgian wind turbines can be built in the German North Sea for instance. This was also brought up by ICEDD [2013], where the study presumes the complementary offshore capacity in other North Sea countries as part of a plan towards 100% RE. However, no agreements have been concluded yet and the willingness of those countries is unknown. [De Standaard, 2018]

Offshore wind turbines only generate value when the produced energy is transported efficiently to the end consumer. Thus, transport modes to bring the energy to the mainland have to be developed as well. Today, transport via electric cables is considered the most cost-effective and is the most widely used way.

As new wind farms still have to be installed, so does the grid connection to the mainland. Sub-sea cables have to be placed to bring the produced electricity onshore. The installation of these sub-sea cables is much more costly than onshore [Jepma, 2017]. In general, the share represented by electric infrastructure can go up to 20% of the total capital cost of an offshore wind project [Boquist, 2015].

In the Belgian North Sea, the first wind farms all have separate sub-sea AC cables but at the moment, a connection platform is being built where various wind farms can be connected to, after which the electricity is transported ashore (OSY MOG on Figure 1.3). The previously mentioned limited Belgian territory in the North Sea may force the Belgian offshore wind power to go beyond the territorial borders. This implies deeper waters and longer distances between wind farms and the coast, possibly implying other types of cables (direct current (DC)) and typically higher costs [Boquist, 2015]. The use of DC requires two converter stations which cost over three times more than a AC substation, making DC only cost-effective after 60-80 km of lines [Electrical engineering portal, 2014] [Sood, 2018].

Moreover, offshore infrastructure has an impact on the onshore grid. With regard to offshore wind energy, the capacity of the onshore electric grid should also be prepared for the electricity transported from offshore wind farms. Generally in the EU, investments in high voltage (HV) lines lag behind. Many lines are outdated and cannot deal with substantially higher amounts of RES.[Buijs et al., 2011] On top of that, multiple barriers are faced with new HV lines projects preventing or delaying them. *"These projects are difficult and time-consuming to site due to the complex relationship between project characteristics, the landscape, individual sentiment, social interaction, the siting process and the political context"* [Cain and Nelson, 2013]. Public opposition has been pointed out by experts to be the primary obstacle. *"Public opposition leads to delays, litigation and major costs"*[Cain and Nelson, 2013].

This was also experienced during the Stevin project in the West of Belgium. In order to connect the last three wind farms out of nine, a 47 kilometers long 380 kV line was built connecting the port city, Zeebrugge, and Zomergem (See Figure 1.3). The new HV line was inaugurated in November 2017 after a process of ten years. Due to public opposition of the local residents, it took Elia, the Belgian TSO, seven years to obtain the permits. Adjustments to the plan, 10 km of underground lines and financial compensations eventually convinced the action groups and municipalities to stop the protest. The whole Stevin project ended up costing 340 million euros, 120 million euros more than foreseen. [Het Nieuwsblad, 2017b]

Since more offshore wind farms will be built in the future, the need for additional infrastructure will rise again. The example of the Stevin project has shown that public acceptance is very limited towards such projects due to landscape and health issues [Het Nieuwsblad, 2017a]. Public acceptance is a determining factor in the project's cost and the timeframe. This should be kept in mind and other alternatives should be looked at when making future decisions.

One of those alternatives to the electric pathway, is power-to-gas where electricity is converted into hydrogen or related chemicals through electrolysis, either offshore or onshore and then transported to the end consumer. In this way, the main grid is not burdened.

1.2.2 Grid-balancing needs

As mentioned before, the fastest growing RES are non-dispatchable and imply inflexibility. Thus, in order to keep the balance between supply and demand in the system, other sources of flexibility have to be introduced [Federal Public Service Economy, SMEs, Self-employed and Energy, 2014]. One of the issues where flexibility is highly needed is the security of supply. At the end of 2017, Elia published a report stating that neither in 2030, nor in 2040, RES will be sufficient to fulfill the entire demand. This is true in different scenarios that already include flexibility measures. Periods of the so called ‘dunkelflaute’ or ‘dark doldrums’ can explain this. These periods take place when very low temperatures are reached, often accompanied by low wind speeds. So, no wind and little sun in winter times result in minimal amounts of RE which are supposed to be the primary energy source in the future. A dunkelflaute can last from several days to two weeks. Such periods are shown in Figure 1.4, which shows that more than 1000 GWh of extra energy supply is needed to cover such a period. This figure is related to the ’flex’ scenario which includes the decentral scenario (18 GW of PV, 11 GW of wind) and additional demand flexibility due to vehicle to grid and demand shifting. Two million EVs (35% of the Belgian car fleet [Febiac, 2017b]) only correspond to 100 GWh, so it appears other solutions are indispensable. [Elia, 2017a]

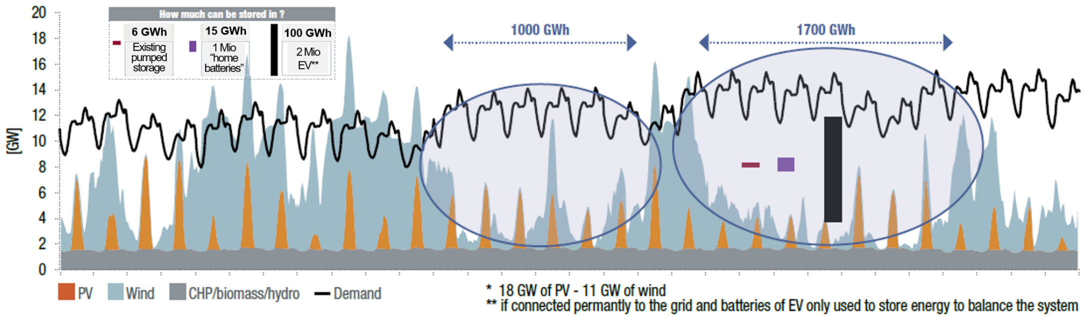

Figure 1.4: Storage needed to cope with long periods with low RES - ’FLEX+’ Scenario [Elia, 2017a]

The same results were concluded by Hamels [2018] stating that in a 100% RE scenario still 2000 GWh would be needed, even with 20 GW of sun and 20 GW of wind. Also in the study *Towards 100% renewable energy in Belgium by 2050* [ICEDD, 2013] the need for grid-balancing is proclaimed, where the capacity factors[2] of both wind and solar installations are considered. Table 1.3 illustrates that wind and solar on average produce respectively 24% and 12% of their maximum production capacity. When periods of 14 days are considered, much lower values are found. Looking at the minimum combined capacity sector, there was a period of 14 days in winter where wind energy reached 13% of its maximum capacity and where PV solar energy was only available for 3% of the time.

[2] A capacity factor can be defined as the ratio of the actual average production / maximum (theoretic) capacity * 8760 hours. It is also called load factor

	Wind	Solar
Average capacity factor	0.244	0.121
Minimum capacity factor in 14 days	0.076	0.017
Maximum capacity factor in 14 days	0.436	0.239
Minimum combined 14 days capacity factor	0.131	0.029

Table 1.3: statistics on the intermittent nature of wind and solar energy [ICEDD, 2013]

Demand-side management (DMS) by demand shifting and shedding could contribute in grid-balancing but their impact is not expected to be sufficient [Elia, 2017a].

One can also rely on imports. However, imports are not unlimited and their supply is uncertain, because there has to be enough capacity available in the neighboring countries. Taking into account the planned interconnections, a maximum simultaneous import level of 6,500 MW has been found by Elia [2017a] but however, it is not guaranteed at any moment that this amount can be delivered. [Meinke-Hubeny et al., 2017]

Instead, thermal generation could fill the gap but these are usually fossil-fired. Moreover, the plants would be characterised by low capacity factors favoring peak load plants with a corresponding higher pollution. In this case, plants with low capital costs and high variable costs are often opted for which are also characterised by lower efficiencies. Nevertheless, new technologies might replace them in the long-term. [Taylor and Taylor, 2015]

In contrast to periods of shortage, considerable amounts of surplus energy are expected as well for the future towards 2050. With a large-scale integration of RES, Elia [2017a] forecasts that in 2030 and 2040 surplus electricity will occur for respectively 10% and 30% of the time. In some hours, there might be 10 GW of excess in 2040. Already today, moments of excess are noticed with extremely low or even negative prices on the day-ahead, intra-day and balancing markets [KU Leuven Energy Institute, 2014]. *"Negative prices simply reflect the inflexibility of supply and the inelasticity of demand"* [WindEurope, 2016]. Such moments can imply 'spilled energy', defined as *"excess energy from renewable generation that has to be curtailed in order to maintain the balance between generation and load (after taking into account all flexibility options such as storage, cross-border exchanges, demand flexibility,...)"* [Elia, 2017a]. Also Albrecht et al. [2017] mentions the issue of overproduction in case of a radical RE scenario. Surplus energy appears when there is a strong irradiation of the sun on Earth, together with high wind speeds. Those moments usually occur outside of the winter season.

To conclude on the previous paragraphs, security of supply always needs to be ensured, with the highest deficits expected in winter, while energy surpluses occur in other seasons. Long-term storage or even seasonal storage could be appropriate to bridge this gap and to bring the needed flexibility to deal with such imbalances along the year. The potential of pumped storage in Belgium has already been utilised. Another storage technology that can offer a solution and store very high amounts (1 GWh - 1 TWh) for a long time (several months) is hydrogen. The hydrogen can be stored in salt caverns of which the cost of storing itself in case of large-scale storage is already very low. [European Commmission, 2017] [HyUnder, 2017]

1.3 Summary of the problem analysis

In this chapter, three issues have been discussed which are all linked to the ultimate goal to mitigate climate change and to be carbon neutral. First of all, the still considerable use of fossil fuels and the need for decarbonisation in different sectors was assessed, where it was also observed that the use of hydrogen in the industry is still mainly produced from fossil fuels. A second issue was found in the rise of offshore wind energy, where bringing offshore electricity ashore in an efficient and cost-effective way poses challenges including costly offshore HV lines and low public acceptance about onshore HV lines. Thirdly, replacing fossil fuels by intermittent RES leads to additional grid-balancing needs and could endanger the security of supply where long-term storage is proposed as a means to bring flexibility. It appears the power-to-gas technology, or the conversion to green hydrogen, with its broad variety of uses, can be a common solution to those three issues. Green hydrogen could contribute in the decarbonisation by being used in industry, transport and the residential sector. Furthermore, hydrogen as energy carrier could avoid the need for new HV lines while at the same time, hydrogen offers opportunities for long-term storage.

1.4 Research question

The defined problems leads to the following research question:

"What is the role of green hydrogen in Belgium's future energy system?"

Three sub-question have been derived which deal with the three issues mentioned before:

1. *What is the future demand for green hydrogen in Belgium?*
2. *Under what circumstances can offshore wind power be the source of an efficient an cost-effective hydrogen production?*
3. *What is the future need for long-term storage to support Belgium's electricity system and under what circumstances will hydrogen be a feasible storage solution?*

Green hydrogen relates to hydrogen produced through electrolysis from electricity from 100% RES. It is also called 'renewable hydrogen'. Consequently, it is carbon neutral.

The *future* Belgian energy system refers to the year 2050. Forecasts will be made for this year. A longer time horizon is chosen in view of the expected substantial changes in the energy system in the near-future, possibly changing the position and need of green hydrogen.

Limiting the scope to the *Belgian* energy system does not imply that only the Belgian territory is included. The demand is limited to the Belgian demand but generation can take place abroad in the form of imports or , as previously mentioned, offshore wind farms in territorial waters of other nations.

Within the Belgian *energy system*, all three sectors are involved being electricity, heat and transport.

The cost-effectiveness and feasibility mentioned in the sub-questions will be studied from a societal point of view.

The next chapter, Chapter 2, gives an overview of Belgium's energy-related markets and grids. Chapter 3 discusses the theory and worldview. Afterwards, Chapter 4 explains the methodology, including the research design and methods. Chapter 5, 6 and 7 answer sub-question 1, 2 and 3 respectively. The discussion is held in Chapter 8 after which it is concluded on the study in Chapter 9.

The organisation of the power, gas and hydrogen market in Belgium 2

Belgium does not have one energy policy but multiple. As discussed before, responsibilities are spread over the Federal (national) and Regional level. In general, the transmission of both gas and electricity is dealt with by the Federal Government whereas the distribution is a Regional responsibility [Federal Public Service Economy, SMEs, Self-employed and Energy, 2018b]. In 2007, the energy market was liberalised making the different grids accessible to many players. The electricity and gas market are discussed in more detail in this chapter, with a focus on the transmission level. Next to that, the hydrogen market is also addressed. In this way, the reader understands the underlying context and can see the framework green hydrogen would fit in.

2.1 Electricity grid

The Federal State is authorised to manage the infrastructure at the transmission level (150-380 kV) including production, storage and transport. The Federal State is also responsible for the security of supply and tariff policy [Federal Public Service Economy, SMEs, Self-employed and Energy, 2018b]

In 2001, Elia was given the legal monopoly as Belgium's TSO for 20 years. Next to the federal level, Elia is also responsible for the transmission networks with a voltage of between 30 and 70 kV which are managed regionally. The monopoly position has put Elia under strong supervision of regulators, both with regards to general supervision of the energy system and approval to tariff setting. Elia also has a public service obligation meaning that the TSO should always guarantee electricity quality and needs to buy green certificates. [Elia, 2017b]

To be more specific, Elia Group [2015] expresses its activities as:

- Electricity system operation: continuously managing the balance between electricity generation and demand
- Infrastructure management: maintenance and development of HV lines
- Market facilitation: Europewide mechanisms and services to ensure safe and affordable electricity for all

Driven by the EU objectives, Elia's three main objectives are [Elia Group, 2017]:

1. Security of supply

2. Construction of the European market
3. Integration of renewable energies

Elia operates over 8,000 km of electricity lines throughout Belgium. In view of the European market, an interconnected electricity system is aimed for. The Belgian grid is already connected to the Netherlands, Luxembourg and France, and will be connected to Germany and the UK in the next two years.

In this study, all TSO's activities are considered at some point. Research question 2 and 3 relate to the activities *infrastructure management* and *electricity system operation* respectively. At the same time, delivering safe and affordable electricity is addressed as well as the societal viewpoint, but rather from a Belgian than a European perspective.

The distribution is fully managed at the Regional level. The distribution system operators (DS0s) take care of the distribution of the electricity at lower voltages, i.e. below 30kV. Belgium counts eight DSOs in total, five in the Walloon Region, one in the Brussels-Capital Region and two in the Flemish Region.

Electricity prices are determined by the Epex Spot Belgium, the Belgian power exchange. For 2017, the average price at the day-ahead market (DAM) was 44.58 €/MWh. Belgian DAM prices are usually in the upper part of the Central Western Europe (CWE) group.

RES are supported by a system of green certificates both at the Federal (offshore wind) and Regional level (other RES). When new offshore wind farms are built, a minimum price per certificate is agreed on for a certain amount of time. [CREG, 2018]

2.2 Natural gas grid

Belgium has, like other north-western European countries, a very extensive gas infrastructure [World Energy Council Netherlands, 2017]. Belgium does not possess any gas resources so all of the gas supply is imported from different countries via one of the 18 interconnection points. The transmission network is operated by Fluxys and consists of more than 4000 km of pipelines [Fluxys, 2017]. A map of the infrastructure at the transmission level is shown in Figure 2.1. As can be noticed, there is an overseas interconnection with the United Kingdom. Fluxys also operates a large-scale storage facility (in Loenhout) and the LNG terminal in Zeebrugge.

The natural gas is mainly used for electricity generation, industrial use and heating. As mentioned before, natural gas is the main energy source for (individual) heating. Consequently, the gas consumption is very sensitive to outside temperatures. 179.4 TWh of natural gas was consumed in 2016, of which about half is used for individual heating purposes. [FEBEG, 2017] The electricity and industry sector represent both about 25% of the consumption.Natural gas is expected to play an important role as a transitional fuel in the Belgian energy transition. Flexible plants can complement the RES as nuclear base-load capacity will disappear and in this way, facilitate the pathway towards a 100% RE society [Federaal Planbureau, 2017].

The average gas price in Belgium in 2017 was 17.58 €/MWh. The price increased after very low prices in 2016, 13.90 €/MWh on average.

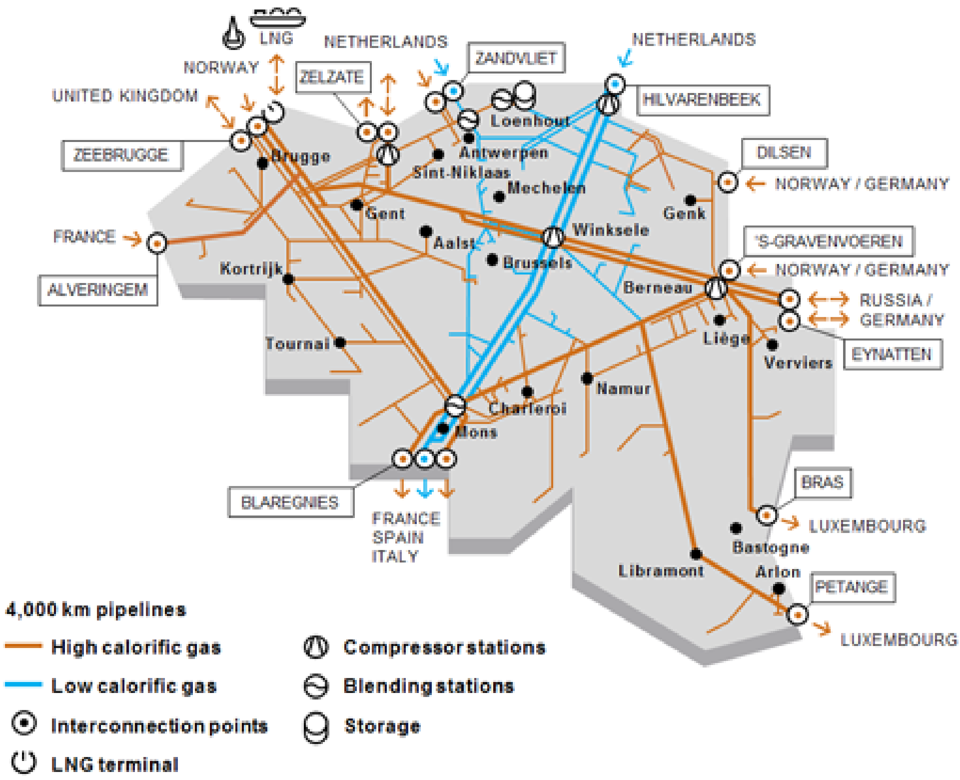

Figure 2.1: Fluxys Belgium's transmission network [Fluxys, 2017]

2.3 Hydrogen market

The hydrogen market consists of three main players which are linked to each other. The market structure is summarised in Figure 2.2 and explained afterwards:

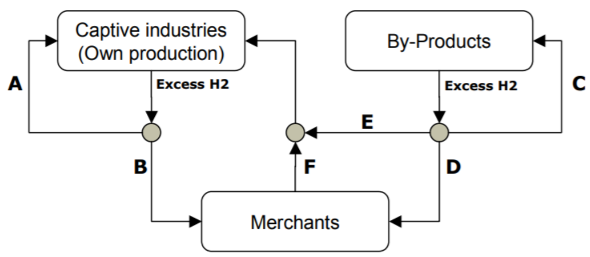

Figure 2.2: Hydrogen market structure [Roads2HyCom project, 2007]

- *Merchant companies* trade hydrogen bought from captive (B), by-product industries (D) or they can act as producers themselves. They sell the hydrogen to captive companies (B) and other specific industries.
- *Captive industries* produce the hydrogen on-site (but in a separate entity) for own use. They can sell their excess hydrogen production to other companies (A) or merchants (B).
- Hydrogen as a *by-product* can be used internally for chemical processes (C), or can be sold to the captive industry (E) or merchants (D).

Globally, hydrogen is 95% of the time produced on-site (captive) and only 5% is traded on the free market by merchants. Belgium, the Netherlands and northern France are an exception to that. A hydrogen grid of 964 km is already in place, of which 613 km is located in Belgium. The grid is owned and operated by Air Liquide and it serves the main industrial clusters. A map of the grid is presented in Figure 2.3. Belgium counts one large-scale SMR production unit for merchant use (owned by Air Liquide) on the BASF site in Antwerp. Apart from that, a few captive installations are owned by oil companies. The network is also fed by hydrogen as a by-product from chlorine-alkali electrolysis, ethylene and styrene production [Roads2HyCom project, 2007]. [WaterstofNet vzw, 2016]

Figure 2.3: Air liquide's gas network in Northern Europe [Air Liquide, n.a.]

The Belgian demand of hydrogen was estimated by the Roads2HyCom project [2007] to be 5.7 billion m^3 per year (equal to about 500 kton or 17 TWh per year). Table 2.1 shows the division within the country. It is clear that the use is primarily located in the Antwerp region which can be explained by refinery activities in the highly present petrochemical industry in the port of Antwerp.

Region	Province	bn m^3/year
Walloon Region		**1.10**
	Hainaut	0.68
	Liège	0.37
	Namur	0.05
Flemish Region		**4.58**
	Antwerp	3.02
	Limburg	0.08
	Oost-Vlaanderen	0.59
Total		**5.69**

Table 2.1: Hydrogen demand in Belgium [Roads2HyCom project, 2007]

Worldview and theories 3

In this chapter, the theoretical framework and the worldview are discussed, which are the foundation for the research approach and analysis in this study. First, the concept of *Smart energy systems* is discussed after which the *Multi-level perspective* is explained. While explaining the latter, the concept of *Transmission expansion planning* is also addressed. More than explaining the theories, they are also applied to the topic of the study.

3.1 Smart energy systems

The concept of *smart energy systems* is used as a basis to make suitable energy planning and infrastructure decisions. Lund [2014] defined this concept as *"an approach in which smart electricity, thermal, and gas grids are combined and coordinated to identify synergies between them in order to achieve an optimal solution for each individual sector as well as for the overall energy system"*. It is opposed to *smart grids* which are solely focused on the electricity grid. Considering the fact that the demand and supply of electricity need to be in balance anytime, managing the future challenges is essential for the electricity sector. However, such 'silo thinking' leads to sub-optimal solutions. When the electricity sector is combined with the other energy sectors, heat and transport, and even industry, more cost-effective solutions can be found for the faced challenges due to renewables. The term *smart* refers to the use of information technology and communication in order to act on this gathered information. [Lund, 2014]

Applications of smart energy systems are power-to-heat and power-to-gas. Seeing that thermal grids, i.e. district heating, are still in a very early stage in Belgium, interaction with this grid is currently less accessible. Hydrogen production belongs to the power-to-gas concept, where cross-sectoral interaction is clearly found in all different application hydrogen can be used for. Not only the option of seasonal storage (interaction between electricity and gas grid) is considered, but it connects the electricity sector to transport, heat and even the industry. It is investigated if other solutions than 'electricity-only' can be cost-effective as well. As mentioned in Chapter 1, multiple issues arise from the electricity-only pathway. This study attempts to find a more optimal solution from the perspective of smart energy systems, thus by combining electricity with other sectors.

3.2 Multi-level perspective

The Multi-level perspective (MLP) introduced by Geels [2002] is another suitable theory that could integrate smart energy systems. MLP is based on a socio-technical approach in order to understand sustainable transitions. Accordingly, sustainable transitions can be explained by interactions between diverse dimensions such as technology, industry, markets, policy, society and culture. Its model consists of three levels, being the surrounding landscape, the well-developed incumbent regime and the emerging niches that aim to enter the regime. They are first shortly introduced to get insight in the big picture, after which they are explained more thoroughly and applied to the sustainable transition discussed in this study, being the decarbonisation by means of green hydrogen.

The landscape represents the external factors, a set of deeply embedded trends such as societal values and the economy. The regime is composed of well-established structures enabling and reproducing the existing systems and technologies. Niches refer to new and emerging technologies (the levels will be explained with more detail later on). The hierarchy and interaction of the different levels are presented in Figure 3.1. The landscape is at the macro-level and puts pressure on the incumbent socio-technical regime, being at the meso-level. It is by this pressure of the landscape 'breaking' the regime that *windows of opportunity* can be created. Those windows can make space for niches (micro-level) to break through and to become part of the regime.[Geels, 2012] .

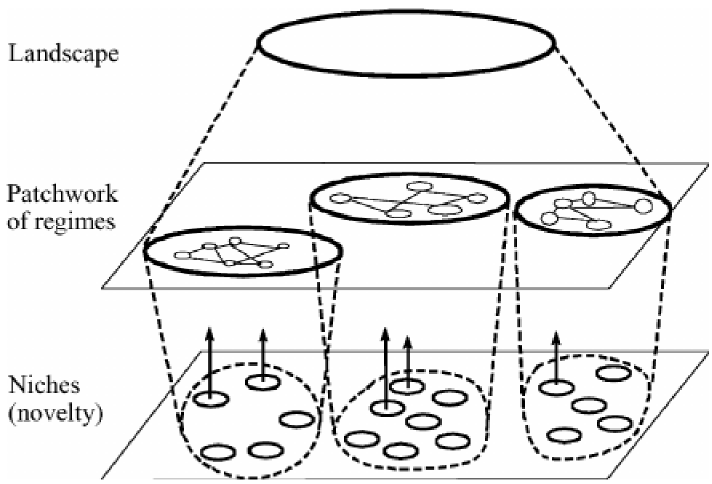

Figure 3.1: Hydrogen market structure [Roads2HyCom project, 2007]

First, the ***regime*** can be seen as a group of institutions which give rise to the current Belgian energy landscape and which are typically resistant to change. The three grids/markets explained in Chapter 2 are part of this regime but also other sectors such as the fossil fuel-dominated transport sector are involved here. The regime is usually established through *path dependency* (1) and *positive feedback mechanisms* (2). (1) *Path dependency* refers to initial conditions, both economic and social, which favour continuation on the previously taken path and typically hampers the energy transition. It implies the dependency of society on given circumstances and conditions which have shaped the regime to how it is today. In the context of this study, examples could be: infrastructure already in place such as petrol stations, grey hydrogen production, current transmission grid ensuring sufficient remuneration etc. (2) *Positive feedback mechanisms* refer to increasing returns when staying in the incumbent system. An example could be learning effects with ICE vehicles where an increasing profitability of the production of conventional ICE vehicles encourages the automotive industry to stay with the current technology.

However, there might become cracks in the regime engendering windows of opportunity facilitating the break through of new technologies. The regime might get destabilised due to pressure from the outside, i.e. the **landscape**. External factors shaping this landscape involve public awareness about political subjects, macro-economic trends, raw materials, cultural elements, beliefs etc. Relating to the topic of this study, the landscape consists of various aspects of the society which have been discussed in Chapter 1 such as the environment and health (resistance against HV lines).

It can be stated that the pressure from the landscape is currently high and that it does play a key role in the sustainable transition. The acknowledgment of climate change and air pollution by both politicians and civil society has an influencing effect. As mentioned before, ambitious strategies have been adopted on both the international (COP21) and the European level. Next, the civil society is also much involved as it can change the daily life of the population.

Apart from the pressure from the landscape, it also appears from a closer look at the transmission grid that the usual path dependency appears not to be valid for an offshore grid. As new wind farms will arise and as they will be installed further from the shore, there will be a need for a new offshore transmission grid. Given that there is no dependency here on the past, new options might be considered instead of seeing an electric grid as the only option. Moreover, rather than positive feedback mechanisms, Chapter 1 mentioned some negative feedback mechanisms such as the Stevin project (new HV line on the mainland) where it was experienced that continuing the 'business-as-usual' is achieved at high cost. 'Business-as-usual' refers here to increasing renewables, offshore wind in this case, while only considering the electricity-only path. The absence of path dependency and the presence of negative feedback mechanisms might overcome the typical resistance to change of the regime.

These observations fit to the concept of *transmission expansion planning* (TEP). TEP is an important element in the evolution of the bulk power system. Capassoa et al. [2015] states that *"the objective of TEP is to guarantee a transmission system (TS) expansion plan that ensures an adequate level of quantity and quality of energy supply, minimizing the inefficiency risk indexes and the operation and investment costs"*. TEP has been an important and difficult task for a TSO for the last decade. Due to the energy transition and the RE targets, there has been lot of uncertainty about the future energy system. Future generation investments are often not known yet when new grid infrastructure is planned. Also in the Belgium North Sea, it is still to be decided where and in which quantity more wind parks will be built. The variable character of RES also implies uncertainty, as it destabilises the extent of payback [Kristiansen et al., 2017]. Furthermore, TSOs are under high pressure by the regulator to keep the transmission network tariffs low. Thus, it is essential that new investments will fit in the future energy system so no resources are wasted. [Buijs et al., 2011] The principle of TEP, i.e. adequate supply at minimal costs, backs the design of the energy systems as well as the economic optimisation and analysis in this study.

It was mentioned above that new technologies can be called **niches**. It is uncertain that a niche will once enter the market and will become a player in the regime, but they are certainly essential in the energy transition. Most niches have a relatively low level of market penetration, often due to a negative economic case. Therefore, they are usually developed in *protected arenas* such as experiments and demonstration projects. Part of the 'protection' is the fact that subsidies often make the niche technology competitive to the regime. [Geels, 2002]

The studied niche in this report is power-to-gas with a focus on hydrogen. Even though hydrogen has been used in industry for a long time and its value was discovered a long time ago, it is still seen as emerging. Hydrogen has to cope with a vague public profile. It has been found that this is mainly due to *"inadequate knowledge on concrete benefits"* and the *"inability to relate to the everyday life"* [Schmidt and Donsbach, 2015]. Furthermore, it appeared that hydrogen is highly supported at a general level, but that is less accepted for specific applications. The aim of this study is to combine both levels, considering production and its different uses.

With respect to protected arenas in the power-to-gas niche, many European and international pilot projects and other initiatives have been started, both about the production and use of hydrogen. Australia announced the construction of a hydrogen production plant fueled by wind and solar power, where it also foresees to become a hydrogen exporter to Japan [RenewEconomy, 2018]. On the European level, many projects arise due to support of the Fuel Cell and Hydrogen Joint Undertaking. An example is HyBalance, a project in Denmark (Hobro) demonstrating the production of hydrogen and its use in energy systems, for balancing the grid and in clean transport [HyBalance, 2016]. In regard to Belgium, Waterstofnet was founded in 2009 as a facilitator of power-to-gas in the South of the Netherlands and Flanders. Together with the industry and governments, they realise projects (e.g. hydrogen fuelling station) and produce roadmaps [Waterstofnet, 2017].

However, S. Bakker [2012] mentions that it is likely *"that more options are available and tried out at the same time - options that jointly challenge the incumbent regime and compete for attention, legitimacy and funding"*. This is also the case for power-to-gas. Power-to-heat could be another technology dealing with imbalances in energy production. Concerning transport, the BEVs have experienced a considerable growth in the last years which might possibly hamper the development of other niches as FCEVs. Indeed, the regime *"serves as a selection and retention mechanism and reduces the variety that originates in the form of radical innovations at the niche level"* [S. Bakker, 2012].

This leads to the approach in this study that power-to-gas cannot be looked from an isolated perspective but that other emerging technologies should be taken into account as well when determining the potential of power-to-gas and hydrogen in the Belgian energy system. Apart from that, it is assumed that the hydrogen niche will break through to some extent, seen the decarbonisation pressure. The competing niches as well as the extent of the breakthrough will be addressed in more detail throughout the report.

Methodology 4

This chapter includes the methods used to find an answer to the research question and the sub-questions. First, the research design is presented schematically in order to understand the structure of this report. The methods mentioned in there are explained more in detail in the following paragraphs. First, the methods for data collection in general are explained. Afterwards, the specific methods used in the three parts (to solve the three sub-questions) are discussed separately.

4.1 Research design

An overview of the research design is given in Table 4.1. The results of the three different parts will give an answer to the overall research question about which role green hydrogen will play in the future Belgian energy system. The preliminary research relates to the problem analysis, while the sub-questions were discussed along with the research question (both in Chapter 1). In the third and fourth column, some more concrete questions are introduced as well as methods for answering them. Chapter 5, 6 and 7 deal with part (row) 1, 2 and 3 respectively.

4.2 Methods

4.2.1 Data collection

In general, data is gathered by consulting literature and conducting interviews. Apart from that, informal communication and internal data at Elia contributed to the methodology of this report. The literature and interviews are discussed in more detail in the next paragraphs.

Literature

Literature research is used as a method to investigate the existing information about hydrogen and power-to-gas.

As part of exploratory research, published studies with regards to the potential as well as news articles are consulted in order to get more insight in the topic and the issues this study aims to solve. The content is not only related to hydrogen but also to the Belgian energy system in general. Similar studies for other levels or countries such as for Flanders, the Netherlands and Europe are also looked at.

Next, specific studies or academic articles are used to collect detailed data about technological or cost aspects. Specifically for costs, the technology catalogue provided by the Danish Energy Agency is used where relevant.

	Preliminary research	Sub-questions	Derived questions	Methods
1	Politic goals (EU,BE), fossil fuels, GHG emissions, grey H_2	What is the future demand for green H_2 in Belgium?	How is green H_2 produced? How is green H_2 transported? What will be the demand for green H_2 in 2050?	Literature review, interviews, sector analysis
2	Offshore wind capacity, electricity transport	Under what circumstances can offshore wind power be the source of an efficient an cost-effective H_2 production?	What are the most cost-effective electrolysis and wind capacities to fulfill the H_2 demand? Can electrolysis offshore be more cost-effective than onshore ? Which circumstances influence the cost-effectiveness of offshore and onshore electrolysis?	Energy system modelling (hourly model in Excel), socio-economic analysis, levelised cost, scenarios, sensitivity analysis
3	Security of supply, intermittent RES	What is the future need for long-term storage to support Belgium's electricity system and under what circumstances will H_2 be a feasible storage solution?	Which excesses and residual load are expected for 2050? Can H_2 play a feasible role in there? Could integration with Part 2 result in economic benefits	Energy system modelling (hourly model in Excel), literature review, socio-economic analysis, levelised cost, system cost

Table 4.1: Research design

Furthermore, the writer attended an international Power-to-Gas conference on May 7th 2018 in Antwerp, Belgium, with as a theme 'From renewables to hydrogen: results an outlook'. New insights on the latest technology and international experiences with concrete cases were shared. Moreover, the regulatory framework was widely discussed. The presentations are used as a source throughout the report (named after the speaker).

Interviews

First, some informal and exploratory interviews have been held. Yannick Schuermans, the Strategy manager of Elia, has been interviewed in order to find out which challenges are faced by a TSO, now and in the future, and how power-to-gas could provide a solution to those challenges. Next, Sam Hamels, a PhD student at the University of Ghent and co-author of Energietrilemma (by Albrecht et al. [2017]) was interviewed and has shared his ideas about the future of the Belgian energy system while also giving advice about the research design and methods.

Secondly, several interviews have been organised in view of gathering specific data. Those were semi-structured as there was a predefined list but at the same time, there was room for follow-up questions to dig deeper into certain topics. An overview of the interviewees is given in Table 4.2. As can be noticed, different stakeholders of the hydrogen chain have been selected. The interviews with F. Smeets and W. Schuytser, S.van Campenhout and R. Feito-Kiczak were face-to-face meetings, while the others were done through a call. Face-to-face interviews are preferred to phone calls as it is easier to interrupt and to ask elaborating questions. However, phone calls where sometimes opted for because of time and geographical limitations. Summaries of most interviews can be found in Appendix A. The internal interviews at Elia (with R. Feito-Kiczak and S. Van Campenhout) are not summarised because they include mostly methodological aspects and concrete numbers, which are cited throughout the report. Next to the interviews, additional data was received via e-mail afterwards when needed.

Name	Company	Job title	Expertise
Isabel François	WaterstofNet	Project Manager	Hydrogen potential Flanders
Filip Smeets Wouter Schuytser	Hydrogenics Europe	Managing Director Process R&D Engineer	Electrolysis
Rene Peters	TNO	Director Gas Technology & North Sea Energy	Hydrogen transport (onshore + offshore)
Steve Van Campenhout	Elia	Extra High Voltage System Developer	HVDC infrastructure
Rafael Feito-Kiczak	Elia	Scenarios, Market & Adequacy studies	Seasonal storage + energy systems modelling
Lars Udby	Hydrogen Valley	Chief Project Officer	HyBalance project hydrogen economy

Table 4.2: Overview of interviewees

4.2.2 Part 1: Green hydrogen demand

The aim of Part 1 is to estimate the total yearly hydrogen demand in 2050. The demand is divided into three sectors: industry, transport and heating in buildings. For each sector, the first step is to determine the current demand (or most recent, depending on data availability). Various reports and data sets are consulted in view of this. If no Belgian data are available, regional data are used and added up. Next, forecasted shares towards 2050 are taken from the estimated current demand, based on the shares in a report about scaling up hydrogen by Hydrogen Council [2017]. These forecasts are complemented by expectations in a study about the potential of green hydrogen in Flanders by the Flemish Energy Agency [2018]. In the next paragraphs, the methodology behind each of the three demands is explained in more detail.

First, two physical parameters are essential in the calculations:

- Density = 0,0899 kg/Nm³ [WaterstofNet vzw, 2016]
- Lower heating value (LHV) = 120.0 MJ/kg = 33.3 kWh/kg
  Higher heating value (HHV) = 141.7 MJ/kg = 39.4 kWh/kg
  The LHV is used in accordance with the European convention [H2FC Supergen, 2014] [The Physics Factbook, 2005]

Industry

The use of hydrogen in the industry is split into two parts: replacing the current (grey) hydrogen demand and new demands that will arise in the future. It is assumed that the current demand in industry is equal to all currently consumed hydrogen. Current use in other applications is considered negligible.

Only data from 2007 are available but they have been corrected by the growth rate of gross value added by the manufacturing industry (at constant prices). In the period 2007-2016, this value has grown by 5.2% [European Commission, 2018d].

The demand in new applications (steel, synthetic fuels and process heat) is based on the current energy demand in these sectors. Shares estimated by the Hydrogen Council [2017] are applied to those demands.

Transport

Here, the current transport demand is the starting point (2016 data). This demand is divided into the different transport modes: road, railway and water transport. Again, shares from the Hydrogen Council are used.

Road transport is subsequently split into the different types of vehicles. For each type, a number of FCEVs (as a share of the current amount) and the average kilometers travelled are estimated for 2050. By means of the hydrogen consumption per km, it can be converted into the hydrogen demand. It is assumed that this fleet remains constant. A rise in passenger cars has been experienced in the last decades but this trend is expected to be offset by a decrease in company cars due to a change in regulation including a decreasing tax advantage and the encouragement of other transport modes [De Standaard, 2017b]. Looking at the other categories, a clear increasing trend has not been observed [Febiac, 2017b].

Railway transport is dealt with in a different way, by looking at the current energy demand by diesel-powered trains that can be replaced.

The demand in water transport is based on the yearly ton-km of inland navigation. This amount is converted into hydrogen demand of which a certain share is considered as hydrogen-powered.

Heating

Hydrogen can either be blended with natural gas or replace fossil natural gas by methanation (to be explained later). Therefore, the natural gas demand forecasted for 2050 is the data started from. The natural gas demand in 2016 which is supplied via the distribution grid is obtained from a report published by the Belgian gas regulator [CREG, 2017]. A projected share of Hydrogen Council [2017] is used to make a forecast of share of hydrogen.

4.2.3 Part 2: Hydrogen as an energy carrier for offshore wind energy

In order to answer sub-question 2, to find out under which circumstances electrolysis connected to offshore wind power can be cost-effective, the starting point is the demand that resulted from part 1 of the analysis.

In the next step, the aim is to find a solution engendering the least costs while fulfilling the hydrogen demand. Supply from by-product hydrogen is not considered due to the few available data about Belgium. In line with the sub-question, offshore wind power is source of electricity. First, it is important to mention that all economic analyses in this study are socio-economic as the solutions to the predefined issues are looked from a societal viewpoint. The socio-economic perspective is opted for because of the scope of the study, i.e. the whole Belgian energy system. This study aims to gain benefit for the society as a whole, while neglecting private owners. This approach implies that transaction costs are excluded, so no taxes and subsidies are considered. Other societal aspects such as employment are not included. The socio-economic analysis is in contrast with the business-economic analysis, where is looked from a private perspective.

Two possible solutions or scenarios with offshore wind power as the common element are defined, which are:

- OFF scenario: offshore electrolysis with a gas pipeline bringing the hydrogen ashore.
- ON scenario: onshore electrolysis where the offshore wind energy is first transported ashore via an electric grid.

A system overview of the OFF scenario is given in Figure 4.1. The wind farm and electrolyser are both located offshore. For the electrolyser, extra infrastructure will be needed such as a platform or island. The produced hydrogen is transported to the shore after which it is distributed towards the different end-users. However, the distribution is not in the scope of this project. Note that the wind farm is in no way connected to the main electric grid and consequently, not to the electricity market either. A study by Jepma [2017] has shown that the combination of both a gas and an electric grid has a negative economic result in all cases, whereas the only gas scenario shows a more positive result. Therefore, a scenario with a gas and electric connection is not considered. Figure 4.1 is complemented by a map (see Appendix B) where this energy system is put in the context of Belgium's marine plan for 2026.

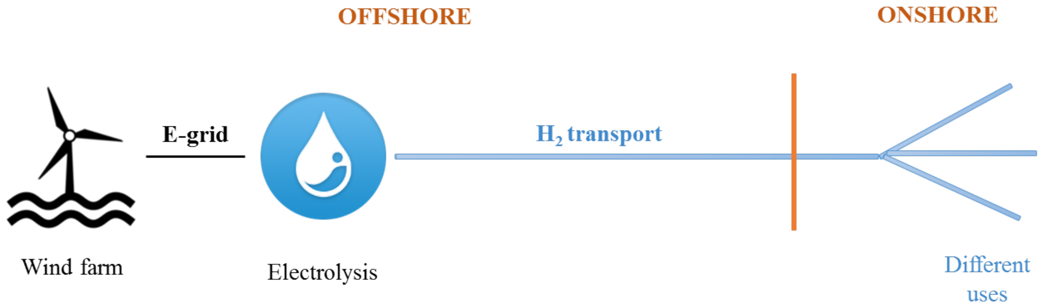

Figure 4.1: Schematic overview of the OFF scenario

The ON scenario is shown in Figure 4.2 where the differences in infrastructure can be noticed. An electric grid is installed connecting the wind farm and the shore after which the electrolysis takes place. Note that the electrolyser is installed near the coast, close to where the electricity reaches the mainland. Also in this case, the wind farm does not consume electricity from the grid. As it concerns *green* hydrogen, only 100% RE is used and this may be guaranteed when taking electricity from the grid. However, the electrolyser can have access to the electricity market to get rid of excess electricity. In this way, extra value could be generated. Again, the distribution is not included in the system.

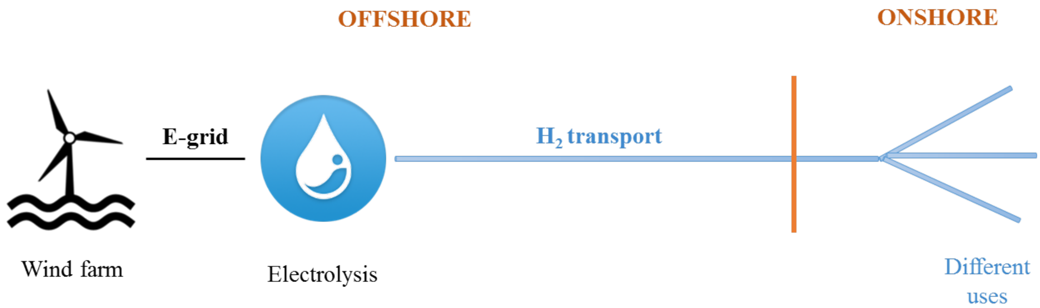

Figure 4.2: Schematic overview of the ON scenario

Note that the electricity input is limited to electricity generated by the wind farm in both scenarios. Hence, the electrolysis operation is fully dependent on the intermittent offshore electricity production. Accordingly, if the electrolyser capacity would be 100% of the installed wind capacity, a considerable part of the electrolyser would be unused for a big part of the time. In 2017, an average offshore capacity factor of 44% was observed meaning that on average, only 44% of the installed wind capacity was available [Elia, 2018]. An optimal electrolyser capacity is usually less than the wind farm capacity [Jepma, 2017]. This also engenders that not all generated electricity can be immediately consumed by the electrolyser. In the ON scenario with onshore electrolysis, the excess can be easily injected into the grid. In the OFF scenario, this is not a possibility so the excess wind power can be either curtailed or stored to be used at a later time. Both solutions entail a cost: in case of curtailment, the production cost has to be covered to avoid system losses, whereas storage needs equipment such as batteries. In this study, the storage option is not considered because of the high costs and lack of experience with offshore use.

The capacity of the wind farm and the electrolyser are essential elements. Hence, the difference just mentioned between both scenarios in grid access requires a separate optimisation of those capacities. Each scenario is first economically optimised before making any comparison. Nevertheless, the methodology followed is the same in both cases. The optimisation is always subject to the constraint that the yearly hydrogen demand (see Part 1) should be fulfilled. Cost minimisation is used as a method and is further explained in the next paragraphs.

An hourly model is set up of which the processes are presented in the first part of Figure 4.5 at the end of this chapter. The electrolyser and wind capacity are variable inputs. Hourly load factors (earlier defined as the ratio of actual production on maximum production) for offshore wind power are obtained from Elia and are based on ENTSO-E data. The efficiency and other technical specifications are given in Chapter 5 and 6. The hourly load factor profile coupled with a certain installed wind capacity leads to an hourly electricity production. The electrolyser can only process the installed power or less. After factoring in electrolysis efficiency, the hydrogen output is obtained.

The economic optimisation within the scenarios (and later comparisons) is based on the concept of *levelised cost of electricity* (LCOE), a method that measures the total cost (including capital costs, operating and maintenance costs) per kWh electricity produced. It is used to compare power generation technologies and it typically does not include grid connection and transmission costs since they are assumed equal for all technologies [Bloomberg New Energy Finance, 2015]. When applied to the production of hydrogen instead, a *levelised cost of hydrogen* (LCOH) can be calculated through Formula 4.1. The yearly production is per weight instead of energy in order to compare to market prices which are usually expressed in kg.

$$LCOH = \frac{CAPEX annuity + OPEX}{Yearly\ H_2\ production} \tag{4.1}$$

Where,
OPEX = Operational expenses in €/year
Yearly H_2 production in ton/year
CAPEX annuity = extracted from the following formula:

$$CAPEX = \frac{A}{1+i} + \frac{A}{(1+i)^2} + ... + \frac{A}{(1+i)^n} \tag{4.2}$$

Where,
$CAPEX = Capital\ expenses$
$A = Annuity$
$i = discount\ rate$
$n = lifetime$

Given the socio-economic perspective, the social discount rate is used which is usually lower than a private discount rate. "*The social discount rate reflects the opportunity cost of capital from an inter-temporal perspective for society as a whole*" [European Commission, 2014]. In Belgium, a social discount rate of 4% is normally used[Feito-Kiczak, 2018]. The system lifetime is 20 years. Some components have shorter lifetimes but this is taken into account by adding replacement costs.

As shown by Formula 4.1, the LCOH includes the annuity of the capital expenses as well as the operational expenses per year. Both are dependent of the the installed electrolyser capacity and the wind capacity. All prices are excluding value added taxes (VAT) because of the socio-economic perspective. When prices applicable to the business environment are used, this deviation counts in both scenarios and does not influence the result. The prices are all at the 2017 level, so any projection towards 2050 does only relate to technical improvements, economies of scale or learning curves. When only data of other years are available, those are adjusted according to the inflation in Belgium. Concerning offshore infrastructure, specific offshore costs are searched for but if they are not available, onshore costs are multiplied by factor 2. This is in line with Peters [2018] and the projected difference between the LCOE of offshore and onshore wind by 2050 [Elia, 2017a].

For each scenario, the LCOH is calculated for different combinations of electrolysis and wind capacities, while always preserving that the demand is met. In this way, the capacities with the lowest cost and socio-economically optimal can be pointed out.

The next step is to compare both scenarios on the economic aspect. As the optimal LCOHs have yet been calculated, the scenario with the lowest cost per MWh hydrogen produced can be appointed. The difference between the scenarios is investigated more thoroughly by means of breakdowns of the cost components. Next, the LCOHs are compared to the market price in order to determine the economic feasibility.

A sensitivity analysis is conducted to obtain more insight in the impact of different relevant parameters on the results. Various input parameter are changed (ceteris paribus) and their influence on the LCOH is measured. These influences are compared in order to point out the input parameters with the biggest impact. Also the impact of a change in the setting is investigated by allowing access to grid. This is only relevant for the ON scenario.

Finally, external effects or *externalities* are discussed, being consequences experienced by an external party. The external effects of a project can be negative or positive and can be monetised as well. These external costs and benefits ought to be internalised in the form of taxes for instance. In this study, externalities are discussed separately from the main results and with a qualitative approach.

4.2.4 Part 3: The role of hydrogen storage

Part 3 consists of two aspects. First, the need of long-term storage in Belgium is determined, where the storage is intended to even out fluctuations from increasing RES. Next, it is investigated how hydrogen can play a role in there.

The need for long-term storage is determined by investigating the hourly residual load (deficit) and excess in a 2050 100% RE system. This system is a result of an extrapolation of 2030 and 2040 large-scale RES scenarios by Elia [2017a]. At the same time, the maximum potential for the respective RES is taken into account so as to make realistic extrapolations.

An hourly model in MS Excel is set up including hourly values of the demand, generation capacities and storage. The hourly demand is supplied by Elia and is a forecast for 2040 as there is no data available for 2050. Similar to Part 2, load factors of ENTSO-E are used for the RE generation. A flowchart of the model is presented in Figure 4.3. First, the electricity yield of the intermittent RES and the must-run capacity is simulated. If the demand is not covered yet, priority is given to spare capacity on the generation units to fill the gap. If there is still a gap afterwards, electricity can be delivered by discharging the storage unit if charged. If there is still unmet demand after these steps, it is considered residual load which implies a need for long-term storage. In case of excesses, the storage unit is charged until its capacity is reached. The excess electricity still left after filling the storage is taken into account when determining the need for long-term storage.

The next step is to investigate how hydrogen can play a role in long-term storage. By means of literature research, different storage technologies are compared and their suitability to long-term storage is assessed.

A new hydrogen storage (power-to-power or P2P) energy system is created which is shown in Figure 4.4. The energy system consists of an electrolyser, a storage facility and a power plant for re-electrification. The capacity of the electrolyser is based on LCOH minimisation, similarly to the dimensioning in Part 2. The excesses that surpass the installed capacity are curtailed at the LCOE of offshore wind (64 €/MWh) given that a big part of the excesses come from offshore wind power. The re-electrification plant is dimensioned based on the peak residual load.

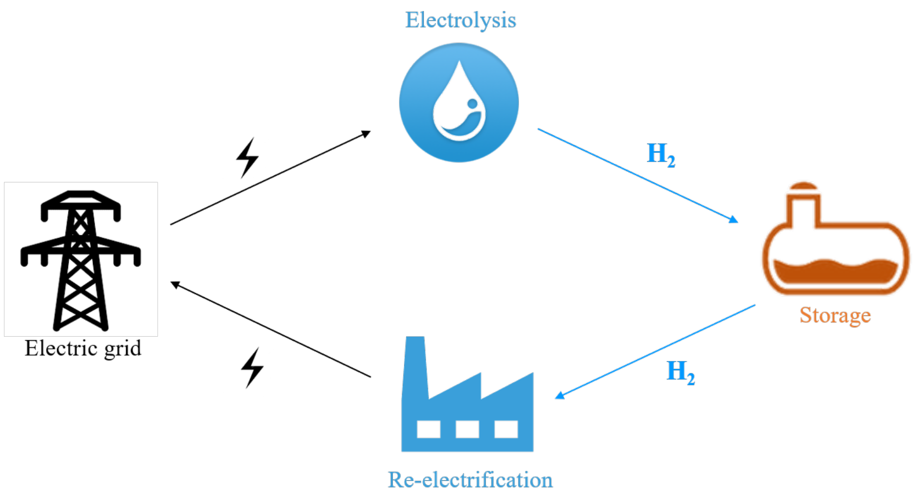

Figure 4.4: P2P system

Next, the cost-effectiveness and feasibility of hydrogen storage is investigated. The analysis is again performed from a socio-economic perspective. Similar to Part 2 of the analysis, the levelised cost method is used to assess the cost of reinjecting 1 MWh of electricity. The hourly excess and residual resulting from the earlier defined hourly model, are used as inputs. The hourly excess serves as input for the electrolyser (instead of wind power in Part 2) and gives a new LCOH. The hourly residual load as input to the foreseen gas turbine capacity results in a utilisation rate that is used for the LCOE calculation. A final levelised cost is obtained by adding up the different levelised cost for 1 MWh of electricity

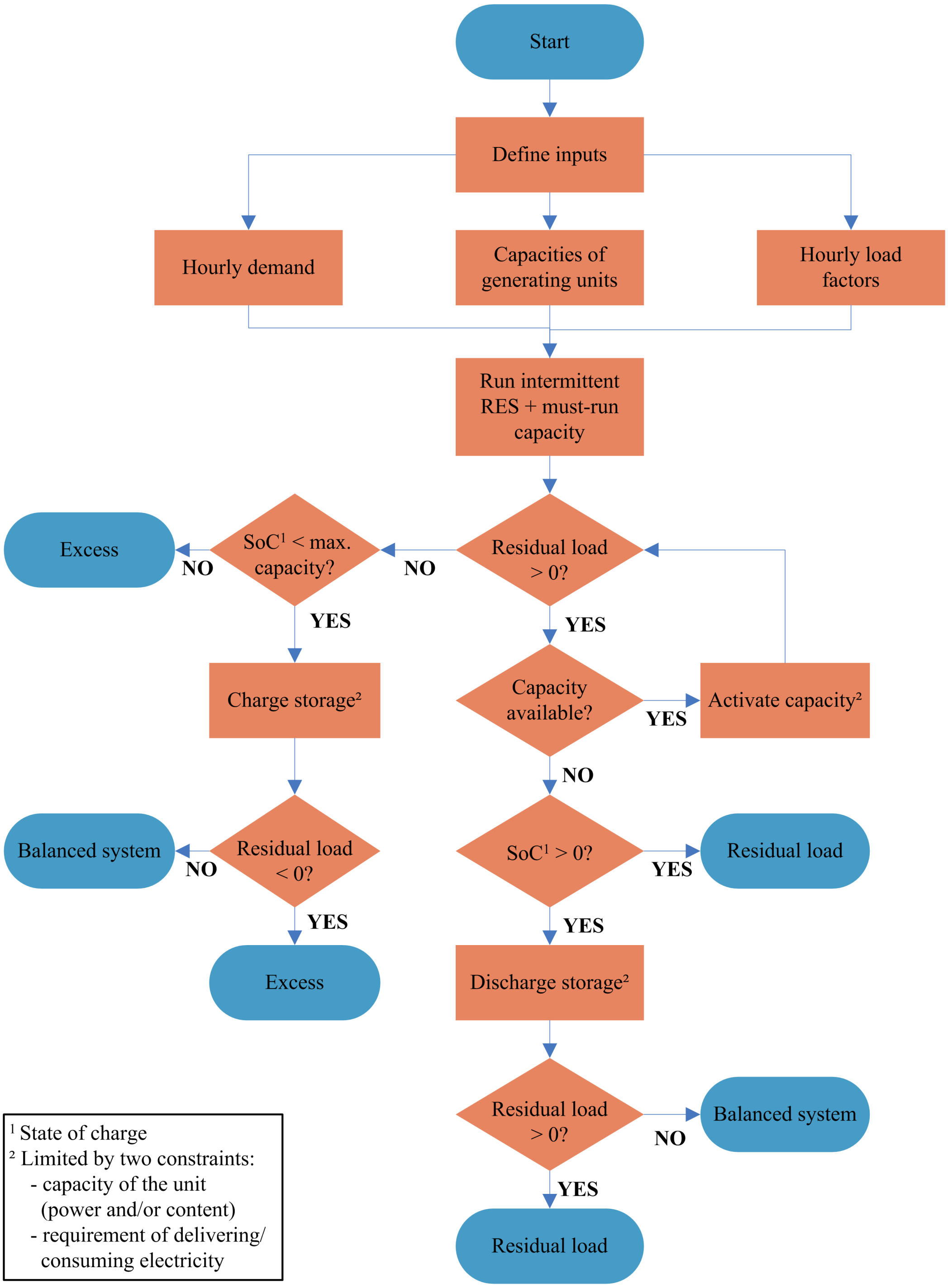

Figure 4.3: Flowchart of the hourly model of the 2050 RES system

output. Accordingly, the economic feasibility is positive if the benefit of reinjecting is equal or higher than the levelised cost.

Differently from Part 2, the cost or benefit when consuming or delivering electricity is not assumed to be constant over time. Following the merit order, the value of electricity on the grid is higher at moments with high demands and low supply, while it is lower at moments with low demands an high supply. The day-ahead market is therefore used for reflecting this value. The market prices used as input are provided by Elia and relate to the 2040 RES scenario. In contrast to the 2050 RES scenario, this scenario includes additional thermal capacity and interconnection capacity, but more appropriate forecasts for 2050 are not available.

Alternatives to hydrogen storage are discussed in a qualitative manner.

Lastly, an integrated approach considers the energy systems in Part 2 and 3 of the analysis as a whole and examines the corresponding system cost related to hydrogen production.

Practically, the excesses found in Part 3 are added as second electricity input to the hourly model of Part 2. The related flowchart is given in Figure 4.5 where all the processes are performed. So, the electrolyser in Part 2 is also used for grid-balancing purposes. The spare capacity capacity after consuming the electricity is now available for the P2P purpose. Next to the electrolyser of the ON scenario, the electrolyser in the P2P system still converts the excesses which are left after filling the spare capacity on the ON electrolyser (See process at the bottom in Figure 4.5. The capacity of the P2P electrolyser is again first optimised based on the LCOH.

The costs of hydrogen produced by the ON electrolyser are allocated to both purposes, the green hydrogen demand and hydrogen storage. This allocation is according to the amount of hydrogen produced. This way of cost allocation was chosen over other allocation methods because of its equal treatment of both purposes. For instance, an alternative would be to assume the electrolyser from Part 2 as given and to only allocate the marginal cost of the additional production but however, one purpose is not considered as outweighing the other on and it is approached as a whole. Moreover, a possible improvement of the initial LCOH of Part 2 is also of interest. Nevertheless, note that the system cost (explained later on) stays the same irrespective of the allocation method. A LCOH for the P2P purpose is obtained by taking the weighted average (according to amount produced) of the levelised cost allocated to the P2P purpose and the levelised of hydrogen produced at the P2P plant.

The integrated system cost is calculated through Formula 4.3. Afterwards this system cost is compared to the sum of the costs of the separate systems.

$$System\ cost = LCOH_{demand} \cdot H_2\ prod_{demand}\ +\ LCOH_{P2P} \cdot H_2\ prod_{P2P} \tag{4.3}$$

with,
$LCOH\ in\ \frac{€}{ton}$
$H_2\ prod.\ in\ ton$

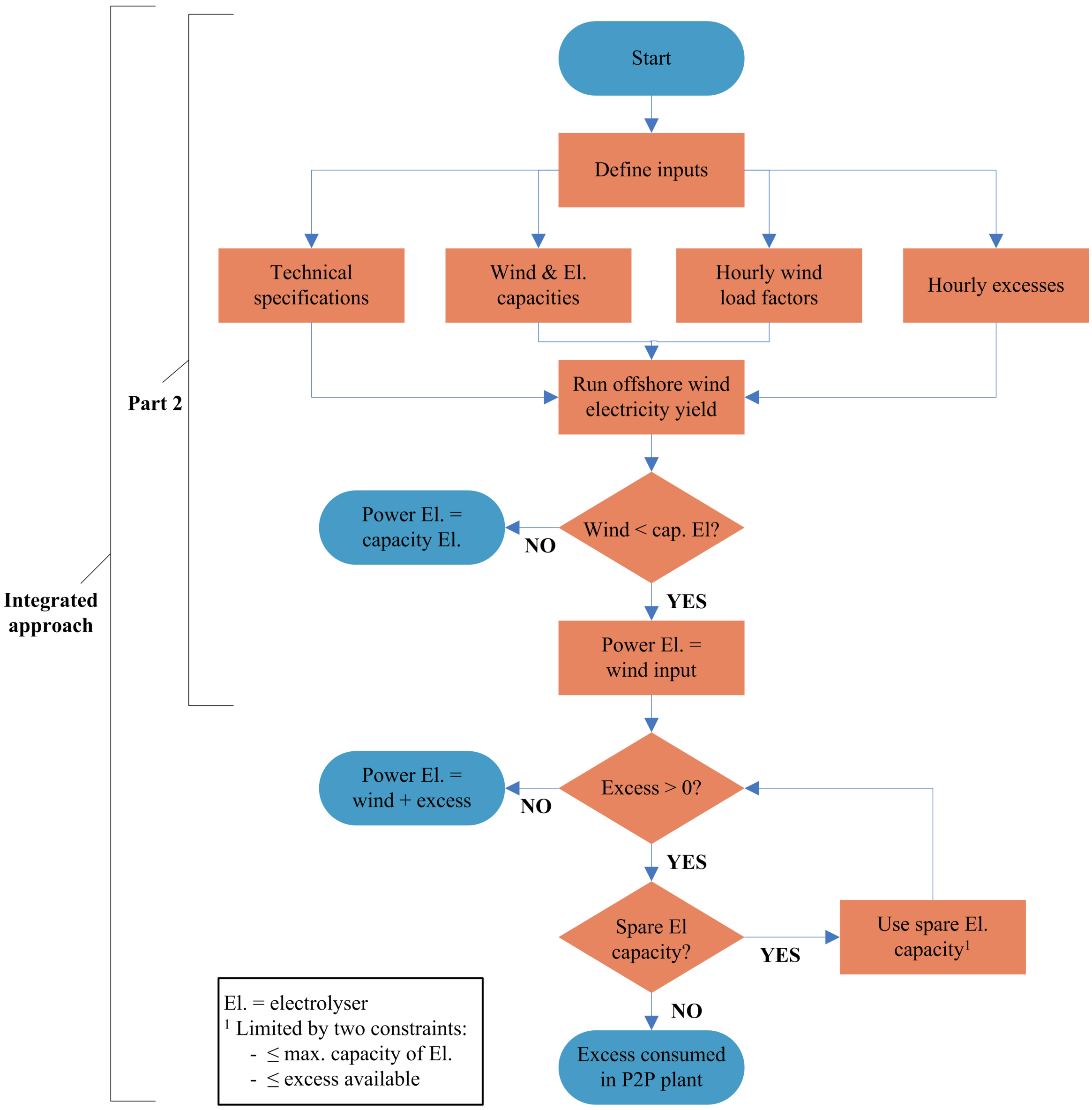

Figure 4.5: Flowchart of the hourly model of Part 2 and the integrated model

Production technology and use of hydrogen in Belgium 5

In this chapter, the technology behind the niche of green hydrogen and power-to-gas is explained first. The existing production technologies are explored and compared to each other in order to choose the one most suitable to the case of this study. The specifications of the technology will also be used in the techno-economic analysis in Chapter 6. The second part of this chapter comprises a forecast of the demand of green hydrogen by 2050.

5.1 Overview of the power-to-gas technology

Power-to-gas refers to the conversion from electricity into gas. The basis is electrolysis, a process where water is split into hydrogen and oxygen as shown in the following formula:

$$H_2O \longrightarrow H_2 + \tfrac{1}{2}\, O_2$$

An electric direct current (DC) is used for an otherwise non-spontaneous reaction. Energy losses occur as heat is wasted during this process that is not valorised elsewhere in this study [Mazloomi et al., 2012]. Nevertheless, a part of the generated heated is reused in the electrolysis process. A schematic overview of the energy inputs and outputs is given in Figure 5.1. The result is hydrogen which is a odourless, colourless and non-toxic gas. As only green hydrogen is considered, the added electricity is 100% coming from renewables. This means no GHG emissions can be related to the hydrogen production. In contrast, the production of one kg of grey hydrogen by means of Steam Methane Reforming (SMR) emits about 10 kg of CO_2 [Engie Laborelec, 2018].

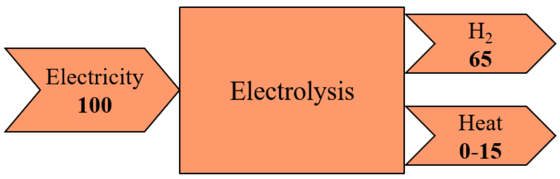

Figure 5.1: An example energy balance of electrolysis (inspired by Danish Energy Agency [2018a])

The electrolysis takes place in an electrolyser. This element represents a big part in the capital expenses related to a power-to-gas system. Two electrolysis technologies are commercialised: alkaline electrolysis and proton exchange membrane electrolysis (PEM). Solide Oxide (SO) is a third electrolysis technology but is still at the R&D stage [IEA, 2015]. Alkaline is the most mature technology and represents the biggest part of the electrolysers in place globally so far. PEM is still in early market stage but the technology is gaining ground because higher installed capacities are getting developed and due to technical performance improvements. This is confirmed by Smeets [2018] (see Appendix A.2). Smeets announces that 20-25MW electrolysers are being designed by Hydrogenics (5MW is currently the biggest capacity, installed in Germany). As Smeets foresees a strong growth in capacity and a decrease of the footprint, he is convinced GW-scale electrolysers will be feasible by 2050.

Technical specifications of the alkaline and PEM electrolyser are shown in Table 5.1. Different recent sources were consulted but it has to be noticed that these specifications might develop quickly. PEM has some advantages such as a higher output pressure, short start-up time, higher power densities, higher potential for efficiency improvements, but it also faces limitations as the shorter lifetime, the water purity requirements and a high investment cost. Nevertheless, due to the assumed future market uptake, high cost reductions are expected [Smeets, 2018]. Its flexibility makes it very suitable to deal with intermittent RES. This has been confirmed in Schmidt et al. [2017] where experts (both academic and industrial) point out PEM as most suitable when intermittent renewables are the power input by 2030. Consequently, the PEM technology will be used in further analyses. [WaterstofNet vzw, 2016] [FCH JU, 2014]

	Alkaline	**PEM**
Maturity	Commercial	Commercial small-scale
Current density [A/cm²]	0.2-0.4	0.6-2
Water in-feed	No specific requirements	fresh water
Output pressure [bar]	<15	<35
Operating temperature [°C]	60-80	50-80
Efficiency (LHV) [%]	51-60%	46-60%
Min. load [%]	20-40%	5-10%
Start-up time to min. load [min.]	20 min-hours	5-15 min
Ramp up from min. to full load [%/second]	0.13–10	10–100
Lifetime [hours]	60,000-90,000	>40,000

Table 5.1: Specifications of the alkaline and PEM electrolyser [Bertuccioli, 2014] [Danish Energy Agency, 2018a] [Buttlera and Spliethoff, 2018]

It is important to note that the lifetime only refers to the cell stack itself. All other components are rather standard technologies. The cell stack in his turn consists of components where the membrane electrode assembly (MEA) is the only one considerably wearing out. One can just disassemble the cell stack, replace the membranes and reassemble. This MEA is responsible for one third of the cell stack cost, where the cell stack represents 50% of the total investment cost. This means only 16.7% of the total CAPEX has to be invested after the mentioned lifetime.

The PEM electrolyser uses demineralised water as input. If the electrolyser is offshore, this implies the seawater has to be desalinated first. The process of desalination can take place through electrical and thermal processes, with a chemical post-treatment. The investment cost for such a unit is high and is therefore only feasible when considerable economies of scale are reached. Since a large-scale electrolyser is foreseen, a large-scale desalination unit is appropriate.

As hydrogen in the Belgian industry is mainly produced by SMR, only a few electrolysers are installed in Belgium. Those are located at the few existing hydrogen fuel stations where both PEM and alkaline technologies are tested [Don Quichote project, 2015]. As it is still a niche, most of them are part of a demonstration project.

The hydrogen resulting from the above explained process can be directly used as feedstock or fuel but it can also be further converted to other end-products such as methane or liquid fuels. Hydrogen gives rise to various valorisation pathways. The different uses will be discussed in the next section.

5.2 Hydrogen transport

A first option is to transport hydrogen via pipelines specifically intended for that purpose. As discussed in Section 2.2, a private hydrogen grid is already in place in Belgium. Also the seaport of Zeebrugge is connected o that grid, possibly facilitating the distribution of hydrogen produced at the shore or in the North Sea. As explained before, the grid is private but however, the hydrogen market might change when the hydrogen economy evolves.

The second option is using the existing natural gas infrastructure, either blended with natural gas at low concentrations or 100% hydrogen. One needs to take into account that hydrogen and methane have other physical and chemical properties. hydrogen could possibly affect the safety and durability [Jepma, 2017]. Peters [2018] started from general technical specification in order to define the suitability of existing gas pipelines. One issue is the fact that hydrogen is a very small molecule and easily leaks through valves, flanges and in compressors. The risk of *leakage* can be mitigated by replacing components or adding seals. So, this means that flanged pipes (usually at distribution level) need considerable retrofitting investments when they want to be used for hydrogen transport. Welded pipes are therefore more suitable concerning that aspect. Another issue is the risk for *hydrogen cracking* where hydrogen makes the pipelines degrade. This occurs mainly with the combination of high pressures and high temperatures or pressure variations. At transmission level, pipes are usually from steel where the risk of hydrogen cracking in case of 100% is expected to be minimal at low pressure (40 bar). [DNV GL, 2017] Consequently, Peters [2018] states no extra investment is expected to be necessary for retrofitting the existing offshore natural gas grid. When other materials imply a higher risk, a special coating could solve the issue.

In general, the risk is lower for low concentrations. A share of 2% is currently accepted as the maximum level to be allowed in Belgium only requiring small investments [WaterstofNet vzw, 2016]. Separating hydrogen when mixed with natural gas is considered by both Smeets [2018] and Peters [2018] as not feasible for small concentrations.

Note that there is limited practical experience with this and that those statements are mainly based on theoretical studies. In the future, higher shares might appear to be more feasible, as well as the suitability of pipe materials might be clarified.

5.3 Future hydrogen demand

Figure 5.2 gives an overview of the different potential uses of hydrogen. It is divided into four use categories. Hydrogen-to-power and its usefulness for seasonal storage are discussed later on in this report. In the next sections, the three other use categories are elaborated.

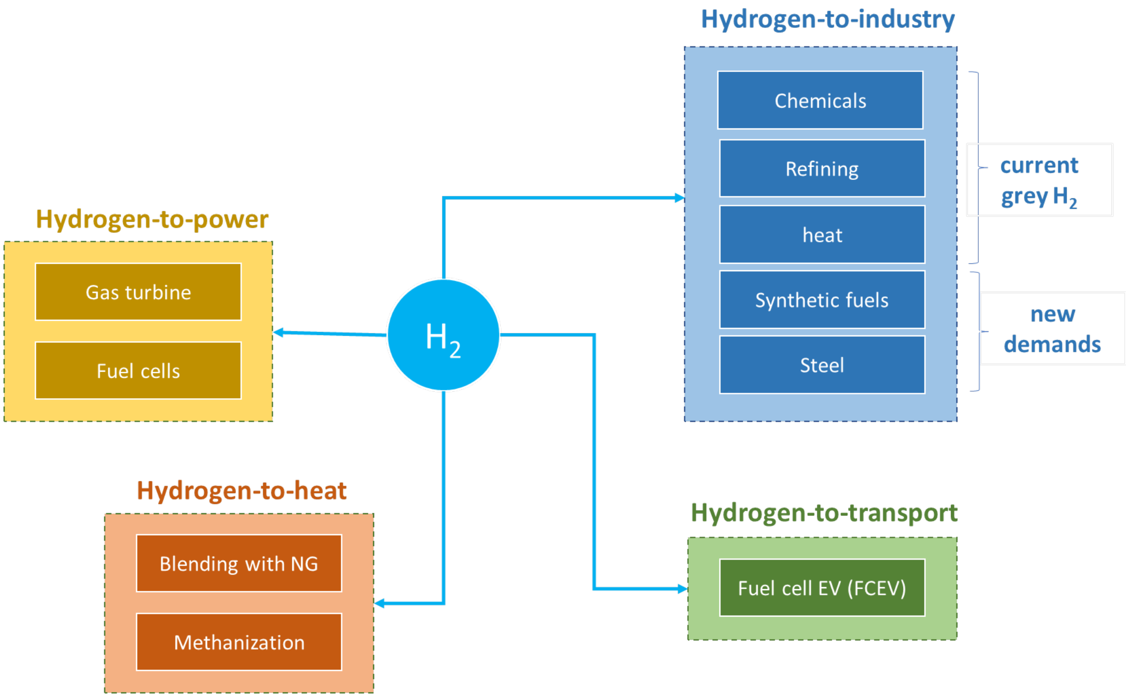

Figure 5.2: Different uses of hydrogen (inspired by European Commission [2017b])

5.3.1 Industry

In general, the hydrogen market discussed in Section 2.2 currently only serves the industry. Hydrogen use is still in its infancy in other applications. Therefore, one of the aims is to decarbonise the existing use of grey hydrogen. Hydrogen is mostly used as a feedstock in chemical and petrochemical industries. In petrochemical industries, it is used in refining processes such as hydro-treating and hydro-cracking. In the chemical industry, the production of ammonia- and nitrogen-based fertilisers consumes the most hydrogen. Hydrogen consumption is also coming from special chemicals production such as polymers. As mentioned before, this hydrogen is nowadays almost always produced from fossil fuels. [IEA, 2012] [Hydrogen Council, 2017] In Figure 2.1, the Belgian hydrogen demand was estimated to be 512 kton by 2007. The industry has grown by 5% from 2007 to 2016 (see Methodology), so correspondingly, a current demand of 538 kton or 18 TWh of hydrogen is estimated. This demand is expected to be fulfilled by green hydrogen for 10% and 50% by 2030 and 2050 respectively. So, by 2050, **269 kton** or **9 TWh** of hydrogen is predicted to replace current grey hydrogen.

Alternatively, there are also processes where hydrogen is not used at the moment, but where it could play an important role in the future. One of those is steel production, which nowadays mainly relies on natural gas as a reducing agent. A pilot plan is being constructed in Sweden where the production is fully hydrogen-based and not emitting anything but water vapour [EURACTIV, 2018]. By 2050, 10% of the steel could be produced in a process using hydrogen instead. [Hydrogen Council, 2017] In Belgium, ArcelorMittal has two large production units, in Ghent and Liege, which produce 5300 kton per year [ArcelorMittal, 2017]. Correspondingly, if **530 kton** of steel would be produced by hydrogen, **31.8 kton** or **1.06 TWh** of hydrogen per year would be needed.

Hydrogen can also serve as feedstock to synthetic fuel production. When CO_2 is added, hydrocarbon-based chemicals such as methanol and other derived products can be produced [Hydrogen Council, 2017]. The CO_2 is typically captured at chemical or process industry because of the significant amounts of emissions [WaterstofNet vzw, 2016]. By 2030, 3% of the consumed methanol is assumed to be produced with hydrogen, while by 2050, this share is assumed 30% [Hydrogen Council, 2017]. The current methanol demand is about 600 kton, which requires 87.6 kton of hydrogen. So, **26 kton** or **0.87 TWh** of hydrogen is estimated to be used for methanol production by 2050.

Next to that, green hydrogen is seen as the main option for decarbonising industrial processes that require high heat (>400 °C). Hydrogen can be the solution when electrification appears not to be feasible or efficient. For instance in blast furnaces, heat can be generated by other combustible fuels than coal such as hydrogen but it cannot be substituted by electrification. With regards to medium (100-400 °C) and low (<100 °C) heat, hydrogen could play a role in hybrid systems with electrification and heat pumps. Shares of 2% and 10% are predicted as the potential by 2030 and 2050 respectively. This corresponds to a hydrogen demand of **229 kton** or **7.64 TWh** by 2050. [Hydrogen Council, 2017]

An overview is given in Table 5.2, where the evolution towards 2050 is shown. The second column shows the demand if 100% would be produced from (fossil) hydrogen. A big increase of the green hydrogen potential from 2030 to 2050 can be noticed. One can also conclude that, next to replacing the grey hydrogen, there is big potential for the new uses by 2050, mainly in steel and heat production. The sum of demands in different applications results in a predicted demand of **103.6** kton or **21.4 TWh** of hydrogen.

	Now	**2030**			**2050**		
	kton fossil	% green H_2	kton H_2	TWh H_2	% green H_2	kton H_2	TWh H_2
Replace grey H_2	538.1	10%	53.8	1.79	50%	538.1	9.0
Steel	318	0%	0	0	10%	31.8	1.06
Methanol	86.7	3%	2.6	0.087	30%	26.0	0.87
Heat	2293	2%	45.9	1.53	10%	229	7.64
Total	**3235**		**102.3**	**10.6**		**103.6**	**21.4**

Table 5.2: Forecasted green hydrogen demand by 2050

5.3.2 Transport

The European strategy towards 2050 concerning transport includes a 60% decrease in GHG emissions and a complete phase-out of conventional ICE vehicles[1] in cities [European Commission, 2011]. As Belgium is Europe's most urbanised country, this phase-out is assumed for all road transport in Belgium. Conventional ICE vehicles will be replaced by BEVs, hybrid EVs, FCEVs and vehicles powered by synthetic fuels (e.g. synthetic methane or methanol). As put forward by the theory, those can be seen as competing niches which means that they should be taken into account when estimating the demand of hydrogen in transport. It does not mean that one niche will win from the other one but rather that one niche will replace that part of the fossil-fuel based transport where the niche has the most benefits.

It was mentioned earlier that the share of hydrogen-powered cars, FCEVs, has been very limited in Belgium so far. However, Hydrogen Council [2017] writes that a third of the global growth in hydrogen demand could come from the transportation sector. In contrast to the image of BEVs and FCEVs as competitors, they could complement each other, with their own strengths and weaknesses. BEVs have higher efficiencies, as long as the battery system does not make them too heavy. Therefore, they are very suitable to light vehicles used for short distances. Conversely, hydrogen has a higher energy density per kg making FCEVs ideally suited for longer ranges and heavy-duty vehicles. Another advantage related to FCEVs, is the fast refuelling time. [McKinsey & Company, 2018]

Figure 5.3 gives an overview of the deployment of hydrogen in the different segments by 2050. First, it is important to underline that those shares are based on data from the Hydrogen Council which is an initiative of leading energy, transport and industry companies. Since those companies might profit from an increasing deployment, the data might be too optimistic as the research might be biased.

As stated before, the attractiveness of the FCEV technology depends on the range requirement (x-axis) and the weight of the vehicle (y-axis). The biggest sales shares of FCEVs are expected for large cars and buses. Also the sale of vans and trucks is expected to rely for more than 40% on FCEVs. Medium-sized/large cars, buses, trucks, vans, trains and forklifts powered by hydrogen are commercially available now or will be within five years [Hydrogen Council, 2017].

[1]Conventional ICE vehicles are non-hybrid vehicles powered by fossil fuels only

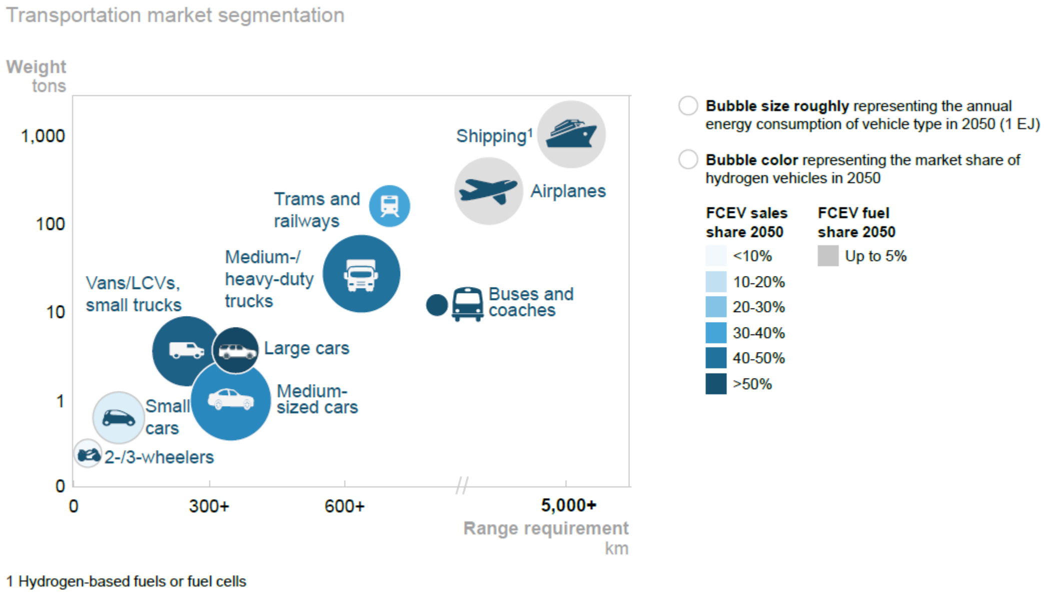

Figure 5.3: Transport market segmentation [Hydrogen Council, 2017]

Toyota puts a strong focus on hydrogen with its Mirai and Honda and Hyundai also have a FCEV in their product range. Figure 5.4 shows how a FCEV works with the example of the Toyota Mirai. The conversion from hydrogen into electricity occurs in a fuel cell where, after adding oxygen, a chemical reaction takes place. This electricity powers an electric motor which also stores electricity in a battery when in generation mode during braking. [Financial Times, 2018] For passenger cars, one can drive up to 130 km with 1 kg of hydrogen and 1 kg of hydrogen replaces 10 kg of diesel. The Toyota Mirai costs € 66,000 on average in Europe which is a lot higher than a similar medium-size petrol or diesel car. The total cost of ownership (TCO) of a FCEV, which includes purchasing, fuelling and maintenance, may become competitive between 2030 and 2040, depending on the mileage. The TCO is expected to become considerably lower than the one of ICE vehicles and close to the TCO of BEVs [Hydrogen Council, 2017]. Hydrogen buses are also gaining ground in Europe because of concerns about air pollution in many cities. Next, trucks and trains are also being developed with many projects planned for the next years, often supported by the Fuel cells and Hydrogen Joint Undertaking (FCH JU). An example is the Revive project where 15 fuel cell garbage trucks will be deployed around Europe of which one will be used in Antwerp. The trucks are built in a new production plant in Belgium. [FCH JU, 2018]

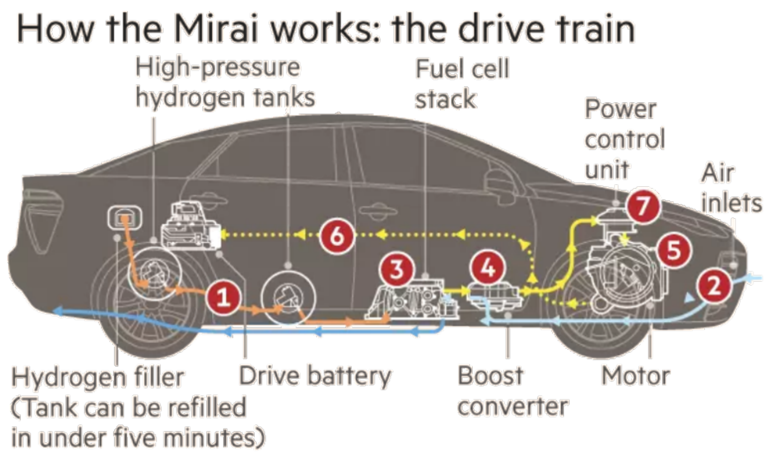

Figure 5.4: How a Toyota Mirai works [Financial Times, 2018]

An overview of the forecasted hydrogen demand in road transport by the different types of vehicles is presented in Table 5.3. The forecasted shares are based on data from Hydrogen Council complemented with data from Waterstofnet[2] and again, that data might be biased and too optimistic.

As can be seen, the transport demand is divided into the different vehicle categories since those have different deployment rates and a different consumption. The starting point is the current fleet that is present in Belgium and it was explained in the methodology that this fleet is assumed to remain constant. Next, the predicted shares of the total fleet represented by FCEVS are given, leading to a certain amount of cars with its corresponding amount of kilometers and finally the required amounts of hydrogen.

The mileage assumed for the car is not the average mileage of all vehicles but is rather an average of the targeted market segment. As FCEVs have their advantage in autonomy, a mileage in the upper range is picked by the Flemish Energy Agency [2018]. [François, 2018] For instance, the average mileage of a passenger cars was about 14,000 km in 2015, while 30,000 km is assumed as the average of FCEVs [Febiac, 2017c].

For each category, the forecasted amount of FCEVs is obtained by taking the predicted share (from Hydrogen Council [2017]) of the current total amount of vehicles. Using the mileage and the consumption, the required amount of hydrogen, to fulfill the demand, can consequently be determined. When the demands of the categories are summed, an estimation of the hydrogen demand in road transport for 2050 is obtained.

[2] Hydrogen deployment facilitator in Flanders and the Netherlands

	2016		2030				2050			
	Total # vehicles	km/year	cons [kg/100km]	Share FCEV [%]	kton H2	TWh H2	cons [kg/100km]	Share FCEV [%]	kton H2	TWh H2
Passenger cars	5730975	30000	0.9	1%	15.5	0.516	0,7	30%	361	12.0
Vans + light trucks (<3,5t)	709836	30000	5	3%	26.6	0.887	4	25%	213	7.10
Trucks (>3.5t)	97548	40000	10	3%	9.75	0.325	8	25%	78	2.60
Trailer	46006	100000	11	5%	25.3	0.843	9	50%	207	6.90
busses	15970	90000	9	10%	12.9	0.431	7	30%	30	1.00
Total	**6600335**				**90.1**	**3.00**			**889**	**29.6**

Table 5.3: Hydrogen demand in road transport

Next to road transport, there is also a potential for hydrogen in railway and water transport. In 2017, a hydrogen-powered *train* was tested in Germany that will be transporting passengers later this year, and 14 more trains have been ordered to be in operation by 2021 [Alstom, 2017] [Reuters, 2017]. In Belgium, a potential can be found in replacing the current diesel-powered trains. As the biggest part is electrified, only 4.5% of the energy consumption comes from diesel (151 GWh) [NMBS, 2016]. Replacing this fully, means 111 GWH or 3 kton of hydrogen per year. The share is expected to develop from 10% in 2030 to 50% in 2050.

For *water transport*, passenger ships seems the most suitable for using hydrogen. In Belgium, one shuttle is already in place organised by the shipping company CMB to bring employees to the centre of Antwerp via the Scheldt [CMB, 2017]. At the same time, the shuttle serves as a testing platform for using the hydrogen technology for commercial sea going vessels in the future. In the case of this project, hydrogen powers an engine but other projects are running investigating the use of fuel cells in shipping. For freight shipping and aviation, hydrogen could also play a role as feedstock for synthetic fuel production. In order to find the potential, the inland navigation is investigated where it is found to represent 4.2 billion ton-kilometers. A big rise in inland navigation is expected towards 2030, with a 62% increase in the period 2012-2030 [Federaal Planbureau, 2015]. Hydrogen-powered ships are expected by [WaterstofNet vzw, 2016] to represent a share of 1% and 5% by 2030 and 2050 respectively. This corresponds to a hydrogen demand of **1.1 kton** or **36 GWh** by 2050.

Table 5.4 gives the total forecasted hydrogen demand by 2050 in the transport sector. It is clear that the biggest amounts of hydrogen are expected to be consumed by vehicles on the road (more specifically, the ones travelling many kilometers). The rest of the transport is covered by other niches such as BEVs.

	kton of H_2	**TWh of H_2**
Road transport	889	29.6
Railway transport	1.51	0.05
Water transport	1.07	0.04
Total	892	29.4

Table 5.4: Hydrogen demand in the transport sector by 2050

Next, charging infrastructure is indispensable to the success of the hydrogen deployment in the transport sector. Currently, there is only one public hydrogen refuelling station in Belgium and a few private ones. However, the Federal Government announced to provide more fuelling infrastructure when the need for it arises [Federal Public Service Economy, SMEs, Self-employed and Energy, 2017]. The Flemish government expressed the aim to have 20 hydrogen fuelling stations in Flanders by 2020 [Flemish Government, 2015]. Such stations are currently still five times more expensive than a traditional petrol station but the cost is expected to decline in the future. The deployment and cost of the fuelling infrastructure is not included in this study.

5.3.3 Heating

In general, various options exist in order to decarbonise the heating sector (after energy efficiency improvements): district heating networks using waste heat, electrification (with heat pumps), solar thermal energy, biomass as a fuel and the replacement of natural gas by green hydrogen.

In this case, heat comprises space heating and domestic hot water in buildings. As discussed earlier, heat is mostly generated on an individual scale in Belgium with natural gas as the most used fuel. This natural gas is supplied by an extensive gas grid. Hydrogen has the advantage that it can use this existing natural gas infrastructure to some extent for delivering it directly to the end consumer. In contrast to electricity, hydrogen can also be stored easily in tanks or caverns.

It was introduced before that it is possible to blend hydrogen with natural gas. However, it needs to be assessed first for the specific case as hydrogen can engender a risk of leakage and pipe degradation. While in Belgium only 2% is generally accepted, Hydrogen Council [2017] states that shares up to 20% could be reached but that would require costly investments to both grid infrastructure and appliances of the end-user.

The other opportunity is to convert hydrogen into methane by a process which is called *methanation*. The following formula shows the reaction:

$$4\,H_2 + CO_2 \xrightarrow{electricity} CH_4 + 2\,H_2O$$

CO_2 and electricity are added in the process with synthetic natural gas (SNG), as it is also called, as a result. A big advantage is the smoother integration as opposed to pure hydrogen because of the long-term experience with handling methane. However, the additional process reduces the efficiency further by 20% while it is also characterised by high costs. WaterstofNet vzw [2016] estimates the LCOE of 2030 and 2050 to be about 75% higher than the LCOE of blending and consequently, it is not expected to be competitive by 2050. Therefore, it is stated that the methanation should only be considered after the maximum injected hydrogen share in natural gas is reached. It should also be noted that biomethane[3] can be a competitor to SNG. Its production is currently more economically feasible [WaterstofNet vzw, 2016]. Recently, the construction of the first biomethane plant in Belgium was announced which will supply 500,000 m^3 or 1.5 GWh per year [Gazet Van Antwerpen, 2018]. More biomethane production is pursued in the future but the available resources are limited.

The third option is the use of hydrogen in micro-CHP based on the fuel cell technology. In contrast to combustion, micro-CHP reaches higher total efficiencies, more than 90%, as also electricity is an output next to the heat [Hydrogen Council, 2017]. Even though the fuel cell technology has experienced considerable market and technical development over the last decade, high investment costs and low lifetimes are still barriers to the deployment.

[3]Biomethane is produced from biogas which results from a fermentation process. By extracting CO_2 from biogas, more pure methane is obtained that can be injected in the natural gas grid. Organic waste is used as input in the fermentation process

As opposed to fuel cells for FCEVs, the cost of fuel cells for stationary use is expected to decrease lower because of the focus on improvements in efficiency and lifetime.[IEA, 2015]

As explained in the methodology, the forecast of the hydrogen demand in the heating sector is based on the natural gas demand. Therefore, the starting point is the current natural gas demand. Only the demand of natural gas supply via the distribution grid is considered so use by industrial clients or for electricity production is not included. As the society is moving away from fossil fuels, the Belgian Government aims at reducing the use of natural gas. In 2050, the use of natural gas in heating is planned to decrease by 62% and 50% for respectively household and the tertiary sector. It is assumed that households are responsible for 65% of the demand while the tertiary sector represents 35%. Table 5.5 shows the demand in 2016 as well as the forecasts for 2050.

	2016		**2050**		
	TWh	PJ	Δ	TWh	PJ
Households	60.28	217.02	-62%	22.90	82.47
Tertiary sector	32.70	117.7	-50%	16.35	58.85
Total	**92.98**	**334.7**		**39.26**	**141.32**

Table 5.5: Natural gas demand by households the tertiary sector in Belgium in 2016 and 2050

Next, different shares of the natural gas demand could be replaced by hydrogen, depending on if it is blended or used for methanation. Table 5.6 shows the injection shares with their corresponding amount of energy required and the mass of hydrogen required. A rather conservative share of 2% is accepted as the current maximum in Belgium. In general, a hydrogen share of 18% is assumed as realistic towards 2050 [Hydrogen Council, 2017]. Accordingly, the hydrogen demand in the heating sector is estimated to be 7.066 TWh in 2050.

	TWh	**kton H2**
2%	0.785	23.55
18%	7.066	212.0
100%	39.26	1178

Table 5.6: Forecast hydrogen in the heating sector by 2050

5.4 Summary

The demand of green hydrogen in the different sectors for 2050 is summarised in Table 5.7. A total of **1.7 million ton** equal to **55.3 TWh** of green hydrogen is predicted. Figure 5.5 shows that the biggest potential can be found in the transport sector, representing more than half of the predicted amount of hydrogen. Next, the industry sector is also responsible for a big part of the predicted demand, while the heating sector only contributes with a share of 13%. Transport is clearly dominant but the fact that there are two sectors well represented, is a positive element, especially when keeping in mind the deployment uncertainty concerning energy technologies. It implies that the role of green hydrogen in Belgium does not merely rely on one sector.

Note that this is rather an ambitious scenario. It requires support to the green hydrogen niche by the policy makers both on the Belgian and European level. Concerning transport, it can be compared to much lower shares proposed by Federaal Planbureau [2017] where one starts from the current reference scenario with an unchanged policy and no new GHG emissions or RE goals for transport after 2020. Here, only 1.5% of road transport fleet is represented by hydrogen. In this scenario ICE vehicles fueled by diesel and petrol still dominate with a share of 67% by 2050. These expectations are much more conservative than in this study, where about 30% of the vehicles are expected to be hydrogen-powered. However, it was thoroughly investigated what potential suits grey hydrogen the best. Next to niches complementing each other, the succeeding in the break-through to the regime is also dependent on the competing niches, e.g. BEVs in transport and heat pumps in heating, as both are options are suitable in certain cases. The time will tell if another niche might 'win' or that the niches could grow next to each other.

	kton H_2	**TWh H_2**
Industry	555.2	18.5
Transport	891.8	29.7
Heating	212.0	7.1
Total	**1659.0**	**55.3**

Table 5.7: Total green hydrogen demand forecasted by 2050

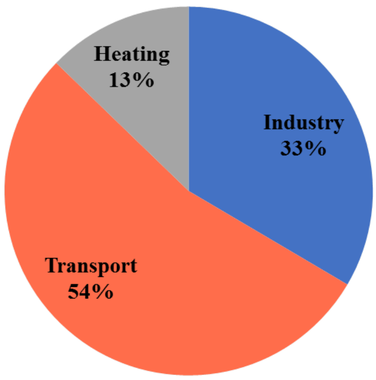

Figure 5.5: Contribution of the different sectors to the green hydrogen demand by 2050

Hydrogen as energy carrier for offshore wind energy 6

In this Chapter, sub-question 2 concerning the cost-effectiveness of hydrogen as an energy carrier for offshore wind energy is answered. First, an overview of the cost assumptions is given. Secondly, the capacities of the energy system in both scenarios are determined. Lastly, the economic feasibility is investigated followed by a sensitivity analysis. The concerned scenarios are the OFF and ON scenario which were presented in Chapter ??.

6.1 Assumptions

This section discusses the cost assumptions used in the socio-economic analysis. It is divided into hydrogen production and energy transport. Note that mostly business-economic costs are used but since this methodological deviation counts for all scenarios, it does not have an impact on the results.

6.1.1 Hydrogen production

An overview of the costs related to the production of hydrogen is given in Table 6.1, followed by a more detailed discussion on the different components.

Electrolysis

Table 6.1 shows the technical and economic assumptions concerning electrolysis predicted for 2050 (but still in 2017 prices). It was concluded before that the PEM technology is the most suitable in this study, mainly because of the ability to operate flexibly, lower maintenance needs and the lower footprint (surface).

With regards to the stated efficiency, this corresponds to a 67% efficiency considering the LHV of hydrogen, being 33 kWh/kg. This efficiency is assumed for partial load as well.

The electrolyser is a central element in the energy systems and therefore, the projection of its cost for 2050 is important and possibly has a big impact on the result. Projections of the Danish Energy Agency [2018a] are used. Those are cross-checked with projections of Smeets [2018] and are in the same line (see Appendix A.2). Taking into account that the CAPEX is assumed 1,000 €/kW for 2020, a 64% cost reduction is expected. Those are partly caused by economies scale due to the growing market, and this growing market will trigger suppliers to invest in the membrane of cell stacks [Smeets, 2018]. Currently, only a few suppliers focus on this technology, but increased competition should lead to technological improvements and cost reductions. The mentioned OPEX in the table are fixed OPEX. Note that there are no variable OPEX, given the very few O&M needs as

Parameter		**Source**
Electrolysis		
Efficiency [kWh-el/kg-H_2]	50	Danish Energy Agency [2018a]
Min. load [%]	5%	Danish Energy Agency [2018a]
Lifetime MEA [hours]	120,000	Smeets [2018]
CAPEX [€/MW]	416	Danish Energy Agency [2018a]
Equipment [%]	50%	Danish Energy Agency [2018a]
Installation [%]	50%	Danish Energy Agency [2018a]
OPEX [€/MW/year] (onshore/offshore)	20,000/40,000	Danish Energy Agency [2018a]
Electricity		
LCOE offshore wind [€/MWh]	64	Elia [2017a]
Fresh water		
Desalination CAPEX [€/2000 l/h]	61,200	Jepma [2017]
Desalination fixed OPEX [% CAPEX/year]	2%	Abbasighadi [2013]
Desalination variable OPEX [€/m^3]	0.75	Abbasighadi [2013]
Tap water [€/m^3]	1.73	Vlaamse Milieumaatschappij [2017]
Offshore platform		
CAPEX [€]	1,750,000,000	Elia internal data

Note: €/MW refers to the price per MW of electricity input

Table 6.1: Input data concerning hydrogen production

mentioned before. The cost related to the electricity consumption is discussed separately in the next section.

Note that those data relate to standard onshore electrolysis. The offshore electrolyser in the OFF scenario requires additional protection against the sea climate and the installation is much more complicated. As motivated in the Section 4.2.3, the CAPEX is therefore multiplied by two.

Electricity input

The cost of electricity that is used in the electrolyser in this study is equal to the LCOE of offshore wind power predicted for 2050. The LCOE is appropriate here taking into account the socio-economic perspective and the fact that the wind farm in the OFF scenario is not connected to the grid. Cost reductions have been observed in the last years as well as more reductions are expected in the future. Elia [2017a] expects the offshore wind LCOE for Belgium to decrease from 130 €/kWh (2016) to 70 €/kWh in 2040. By means of a logarithmic extrapolation, this results in an LCOE of 64 €/kWh in 2050.

The same number is used for the cost of curtailment. When the electrolyser capacity is lower than the offshore wind capacity, part of the wind energy cannot be used an has to be curtailed. As there is no connection to the grid in the OFF scenario, curtailment is the only option, entailing a cost (otherwise losses would be made). In the ON scenario, there is also the option of injecting surplus energy in the grid. In this case, the LCOE of wind energy is offset by the 'delivery' to the grid, which can be seen as adding value to the system as it could be exported.

Water input

As described in Section 5.1, demineralised water is required. In case of the OFF scenario, where there is only access to salt sea water, a treatment of the water is necessary. The reverse osmosis technology is used and the cost of this treatment is estimated by Jepma [2017] to be € 61,200 for 2000 l/h. This cost will be adjusted according to the electrolyser capacity.

In the case of the ON scenario, there is access to tap water so the average cost of water applying to companies in Flanders is used, being 1.73 €/m^3 [Vlaamse Milieumaatschappij, 2017]. The demineralisation is included in the electrolyser cost.

Offshore platform

The cost of the offshore platform, bearing the equipment in the OFF scenario, is based on the cost for the MOG platform which is currently being constructed in the Belgian North Sea as an electricity collector for wind farms (100 x 80 m). The cost amounts to 60 M€ which is scaled to the required measures for the equipment in the OFF scenario. Smeets [2018] says a 25MW electrolyser currently takes 1000 m^3 (40 m^2/MW) and expects that the area footprint will be halved in the next years to 20 m^2/MW. It is assumed that by 2050, this footprint will be halved again as more technical development is expected.

6.1.2 Energy transport

Table 6.2 gives an overview of the input data concerning the cost of energy transport for both scenarios. Accordingly, costs for a gas as well as an electric grid are included. In the AC/DC and DC/AC conversion, no losses are included as current efficiencies are in the 98-99 % range which might only increase in the future.

Parameter		**Source**
Offshore gas pipeline		
CAPEX [€/km]	2,912,000	ACER [2015]
OPEX [€/1000m^3]	16.5	Jepma [2017]
HVDC infrastructure		
Offshore cable [€/MW/km]	1,500	Elia internal data
Onshore converter [€/MW]	130,000	Elia internal data
Offshore converter [€/MW]	450,000	Elia internal data
OPEX [% CAPEX/year]	2%	Elia internal data

Table 6.2: Cost assumptions concerning energy transport

Hydrogen transport

The system includes the hydrogen transport until distributed to the end-user. In the OFF scenario, the hydrogen produced offshore has to be transported ashore. Since there is already an underseas natural gas interconnection between Belgium and the UK, this grid could be used for hydrogen transportation as well. In light of the decarbonization, one assumes that there will be no natural gas flowing through this pipeline anymore, unless synthetic natural gas would be produced and exported. However, no such high quantities are expected for 2050 neither in Belgium nor in other countries that would call for import or export. On top of that, it was stated in Section 5.2 that offshore gas pipelines are expected to be suitable to hydrogen transport without retrofitting. Consequently, the investment in new pipelines is avoided. However, a connection between the electrolysis plant and the existing grid has to be constructed. It is assumed that the location of the gas grid is taken into account when planning the electrolysis plant and the wind farm, and therefore a distance of 1 km is assumed for the gas connection.

Electricity infrastructure

Because the wind farm is assumed to be 110 km away from the shore, HVDC lines are considered. For long distances (greater than 80 km), AC entails significant losses making HVDC the preferred option [World Energy Council Netherlands, 2017]. HVAC cables are more expensive than HVDC cables but no converters are needed. Only offshore infrastructure is foreseen given that the electrolyser is directly connected to the wind farm and is located close the point where the electricity reaches the mainland.

Consequently, there is an offshore electricity conversion from AC to DC in both scenarios. In the OFF scenario, DC is needed as the input for electrolysis while in the ON scenario, the electricity is transported ashore via an HVDC grid. In this case, an onshore DC-AC converter is added so excess electricity (after electrolysis) can be injected in the grid. The offshore converter is assumed to be installed in a range of 90-130 km from the shore, and consequently the cable length is assumed to be 110 km (the average). In the OFF scenario, the conversion is included in the electrolyser cost. In the AC/DC and DC/AC conversion, no losses are included as current efficiencies are in the 98-99 % range which may only increase in the future.

6.2 Energy system capacities

The aim of this section is to find the optimal capacities of both the electrolyser and the wind farm. As explained in Section 4.2.3, the socio-economic LCOH is minimised while supplying at least as much hydrogen to fulfill the forecasted demand for 2050. Concerning annuities of an investment cost, a discount rate of 4% and a lifetime of 20 years is used (see also Section 4.2.3).

Both scenarios are optimised separately as differing assumptions apply, influencing the LCOH. The optimization of the OFF scenario is shown in Table C.1 where the LCOH of various combinations is calculated. A color scale is used to indicate higher and lower cost combinations and the lowest ten values are framed. The levelised cost is higher in case of a low electrolyser capacity combined with a high wind capacity. In this case, there is a lot of excess electricity which cannot be converted in hydrogen and cannot be valorised. On the other hand, the cost also increases when the electrolyser capacity becomes bigger than the wind capacity. A part of the electrolyser capacity would be continuously unused in this case resulting in low utilisation. So, the investment for additional electrolysis capacity cannot be earned back. The framed values in the green band all belong to a combination where the electrolyser capacity is smaller than the wind capacity.

Offshore wind capacity [MW]

Electrolyser capacity [MW]

LCOH [€/ton]	22000	22500	23000	23500	24000	24500	25000	25500	26000
15000	5,423	5,453	5,484	5,516	5,549	5,582	5,616	5,651	5,687
15500	5,382	5,410	5,439	5,468	5,498	5,530	5,561	5,594	5,627
16000	5,346	5,371	5,398	5,425	5,453	5,482	5,512	5,542	5,574
16500	5,315	5,337	5,361	5,386	5,412	5,439	5,467	5,496	5,525
17000	5,288	5,308	5,329	5,352	5,376	5,401	5,427	5,453	5,480
17500	5,265	5,282	5,301	5,322	5,343	5,366	5,390	5,415	5,440
18000	5,246	5,261	5,277	5,295	5,315	5,335	5,357	5,380	5,404
18500	5,230	5,243	5,257	5,273	5,290	5,308	5,328	5,349	5,370
19000	5,219	5,228	5,240	5,253	5,268	5,285	5,302	5,321	5,341
19500	5,213	5,218	5,227	5,237	5,250	5,264	5,280	5,297	5,315
20000	5,213	5,213	5,217	5,225	5,235	5,247	5,261	5,276	5,292
20500	5,221	5,213	5,213	5,216	5,224	5,233	5,244	5,257	5,271
21000	5,245	5,222	5,214	5,212	5,216	5,222	5,231	5,242	5,254
21500	5,287	5,247	5,223	5,214	5,212	5,215	5,221	5,229	5,239
22000	5,331	5,288	5,248	5,224	5,214	5,212	5,214	5,220	5,228
22500	5,375	5,331	5,289	5,250	5,225	5,215	5,212	5,214	5,219
23000	5,418	5,374	5,331	5,290	5,252	5,226	5,216	5,212	5,213
23500	5,462	5,416	5,373	5,331	5,291	5,253	5,227	5,216	5,212
24000	5,506	5,459	5,414	5,372	5,331	5,292	5,255	5,228	5,217
24500	5,549	5,502	5,456	5,413	5,371	5,331	5,293	5,256	5,229
25000	5,593	5,544	5,498	5,454	5,411	5,370	5,331	5,293	5,257

Figure 6.1: Levelised cost of hydrogen as a function of electrolyser and wind capacities the OFF scenario

Taking into account the restriction to produce at least the forecasted demand of 1659 ton hydrogen, it appears the combination of 22000 MW (22 GW) and 24500 MW (24.5G W) is optimal for the OFF scenario. This corresponds to an LCOH of 5,212 €/ton H_2. With those capacities, the average electrolyser utilization rate is 43% meaning that on average, more than half of the capacity is unused. The rate is rather low but a trade-off has to be made between on the one hand, increasing the wind capacity and increasing the utilisation rate, and on the other hand, high curtailment.

As the electrolyser capacity is 2.5 GW less than the wind capacity, the electrolyser capacity is 90% of the wind capacity. This means that there will be electricity surpluses in hours with a load factor above 90%. The curtailment is shown in Figure 6.2 by a load duration curve. The small area between the orange and blue curve represents the surplus energy that has to be curtailed, whereas the coloured area is equal to the effective generated wind energy that is consumed by the electrolyser.

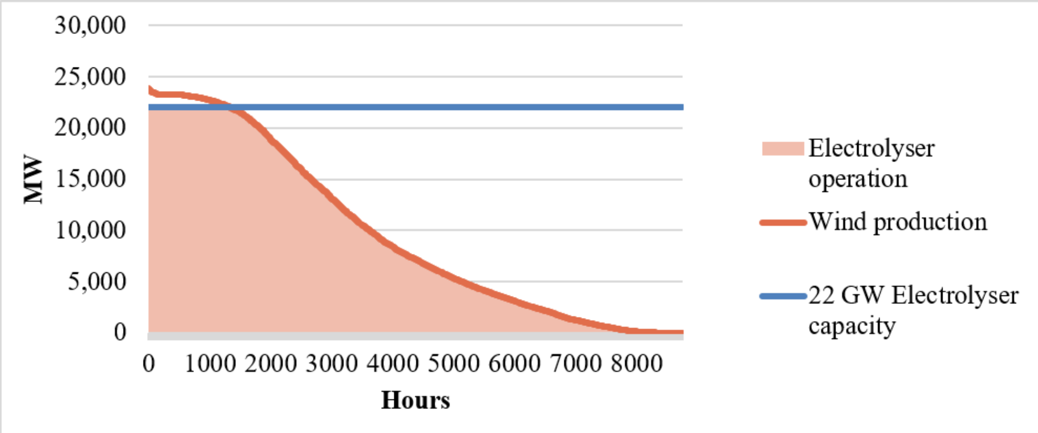

Figure 6.2: Load duration curve the OFF scenario

The same process has been conducted for the ON scenario. Equal optimal capacities are found compared to the OFF scenario, being 24.5 of wind capacity and an electrolyser capacity of 22 GW. This combination corresponds to a levelised cost of 4,484 €/ton. A table with levelised costs of changing capacities of the ON scenario can be found in Appendix C. Because of the equal capacities, the load curves are the same as well. The fact that the outcomes of both optimisations is the same will become clear in the next section.

A summary is given in Table 6.3. It can already be concluded that the levelised cost in the ON scenario is lower than in the OFF scenario. However, the economic feasibility and the comparison between the scenarios is more elaborated in the next section.

Scenario	**Wind capacity [GW]**	**Electrolyser capacity [GW]**	**LCOH [€/ton H_2]**
OFF	24.5	22	5,212
ON	24.5	22	4,484

Table 6.3: Summary of the scenario's optimal capacities and their levelised cost

6.3 Economic analysis

This section includes the socio-economic analysis of both scenarios. The LCOH results are further analysed. First, an overview is given of the costs of the OFF scenario and the ON scenario corresponding to the optimal capacities determined in the previous section: 22GW electrolysis and 24.5GW wind capacity. Table 6.4 (the OFF scenario) and 6.5 (the ON scenario) present a breakdown of the costs separated into CAPEX and OPEX.

Concerning the OFF scenario, the CAPEX is clearly dominated by the electrolyser investment, which includes the entire electrolyser in the beginning as well as the replacement of the membrane after 120,000 hours. Next to that, the platform supporting this electrolyser also has a considerable contribution to the CAPEX. The OPEX primarily consists of the cost of electricity required in the electrolysis process.

CAPEX [M€]	**20,270**
Electrolyser	18,304
Platform	1,650
Water desalination	316
Gas pipeline	3
Membrane replacement (after 120,000 hours)	7,845
OPEX [M€/year]	**6,641**
Electricity cost	5,431
O&M electrolyser	880
O&M water desalination	23
Gas transport	307

Table 6.4: Overview of the costs in the OFF scenario

The CAPEX of the ON scenario consists of a lower electrolyser cost as the cost for offshore equipment was twice as high in the OFF scenario. The total CAPEX is lower than in the OFF scenario but considerable more than the half (as could be expected because onshore costs are doubled when offshore). This is due to the cost of the HVDC infrastructure which is also relatively high. The OPEX is again dominated by the electricity consumption.

CAPEX [M€]	**16,502**
Electrolyser	9,152
HVDC infrastructure	7,350
Membrane replacement (after 120,000 hours)	3,922
OPEX [M€/year]	**5,990**
Electricity cost	5,364
O&M electrolyser	440
Fresh water	39
O&M HVDC infrastructure	147

Table 6.5: Overview of the costs in the ON scenario

These CAPEX and OPEX are inputs of the LCOH calculation. The specific components, i.e. the annuities and production, are shown in Table 6.6. The total annuity is dived by the amount of hydrogen produced resulting in the levelised cost of producing 1 kg of hydrogen. As mentioned before, the LCOH of the ON scenario is the lowest. The significant difference can be explained by both higher CAPEX as well as higher OPEX. The CAPEX of the OFF scenario is higher due to the additional expenses as all equipment is placed offshore which appear not be compensated by the new HVDC infrastructure in the ON scenario. The amount of hydrogen produced is equal in both cases because the same wind and electrolysis capacities apply.

	SC OFF	**SC ON**
Annuity [M€/year]	8,693	7,493
CAPEX	2,069	1,503
OPEX	6,624	5,990
H_2 production [t/year]	1,671,109	1,671,109
LCOH [€/t]	5,202	4,484

Table 6.6: Build-up of the LCOH

When the CAPEX and OPEX of both scenarios are presented visually in Figure 6.3, it is striking that the OPEX is much higher than the CAPEX annuity. Consequently, it seems the OPEX plays an important role in the LCOH and the economic case of the scenarios. The OPEX of the OFF scenario is the highest but the relative difference with its CAPEX is smaller. These observations make it relevant investigating the OPEX more thoroughly.

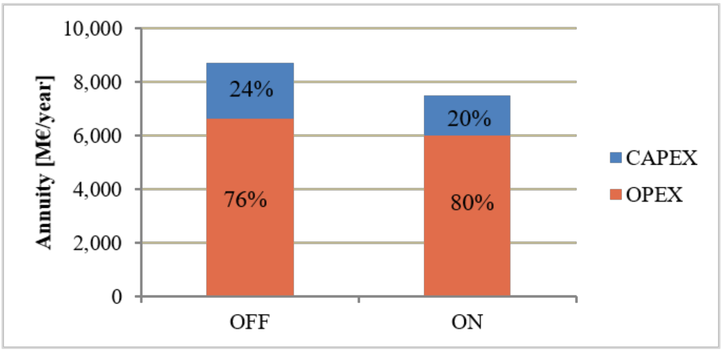

Figure 6.3: OPEX and CAPEX annuities for the OFF and ON scenario

The relatively small difference in OPEX can be explained by the fact that the OPEX in both scenarios mainly consists of the electricity production cost. This is clearly shown in Figure 6.4, where the cost of electricity is responsible for 81% of the OPEX in the OFF scenario, and even for 89% in the ON scenario. As the electricity cost is at the same scale in both scenarios, it means a big part of the OPEX is similar as well. In the ON scenario, a part of the surplus energy is injected into the grid though, reducing the electricity expenses. However, as the electrolyser and wind capacity are relatively close to each other, the surplus energy is rather low and so is the cost reduction. The additional CAPEX is dominated by the O&M of the electrolyser which is higher in the OFF scenario because O&M is more costly when offshore.

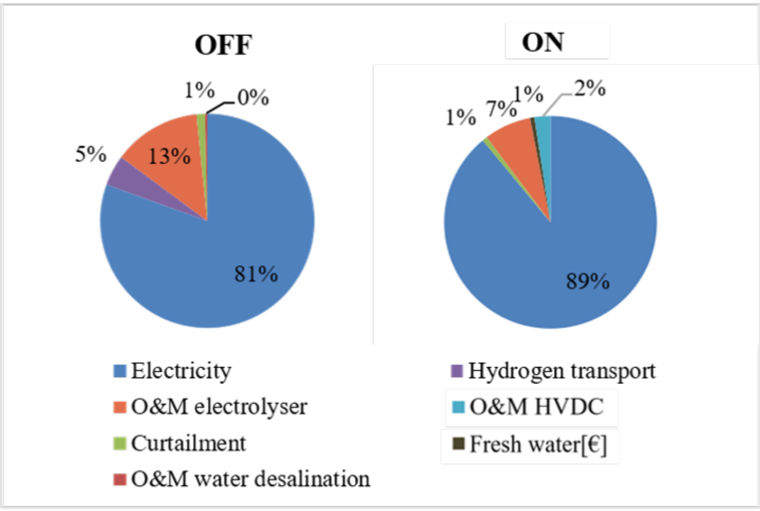

Figure 6.4: OPEX breakdown

It is also interesting to break down the annuity (OPEX and CAPEX) into hydrogen production and energy transport. As shown in Figure 6.5, the amount attributable to energy transport is considerably bigger in the ON scenario than in the OFF scenario due to the new HVDC infrastructure, while mainly an existing gas grid is used in the OFF scenario. The higher costs related to hydrogen production are again due to the offshore activities. It can also be concluded that the energy transport in the system only represents a small share in the total cost. Consequently, the way of transporting does not play a big role in the economic feasibility, limiting the advantage of the OFF scenario regarding the use of existing gas pipelines.

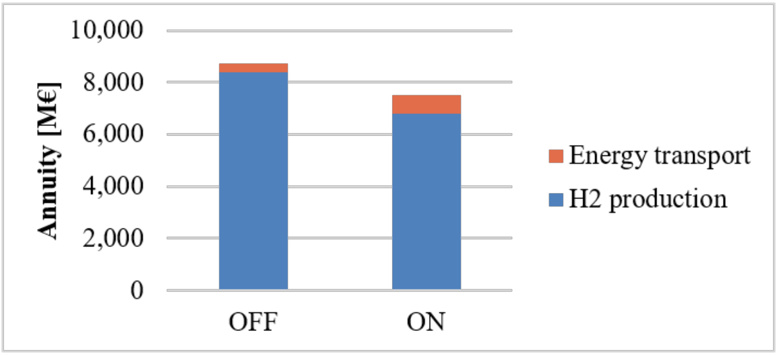

Figure 6.5: Annuity breakdown: hydrogen production - energy transport

So far, only the cost related to green hydrogen has been discussed. The LCOH serves as a base of comparison but also as a measure of necessary income or benefit to cover this levelised cost. Green hydrogen has to compete with grey hydrogen whose production and market is already well established. The market value of grey hydrogen from large-scale production is about 2 €/kg or 2,000 €/ton. However, the CO_2 price in the EU ETS is expected to increase considerably by 2050 which would make the grey hydrogen price increase. The European Commission expects that this CO_2 price will evolve from 6 €/ton to 88 €/ton CO_2 by 2050. As production of hydrogen by SMR emits 10 kg CO_2 per kg H_2, 0.88 €/kg H_2 is added. This results in a grey hydrogen price of 2.88 €/kg (instead of 2.06 €/kg now) or 2,880 €/ton.

Neither of the scenarios' levelised cost can be covered by that amount, with LCOHs of 5.2 and 4.5 €/kg for the OFF scenario and the ON scenario respectively. The gap is still 2.3 and 1.2 €. This means also that the CO_2 price per tonne should increase with 232 and 118 euros respectively in order to cover the levelised production cost. However, there are other impacting factors as well such as the natural gas price. If the natural gas price increases, the cost of producing hydrogen through SMR will go up as well. WaterstofNet vzw [2016] assumes such an increase and accordingly expects the hydrogen price to be 3.59 €/kg by 2050. Nevertheless, its development is very uncertain.

Note that other market prices might be applicable when comparing to other fuels. For instance, to be competitive to the socio-economic cost diesel for transport, 5 €/kg[1] is the benchmark.

Apart from a change in the hydrogen value, it is also possible that cost components appear to be lower or higher by 2050 impacting the feasibility of green hydrogen production. This effect is discussed in more detail in the next section.

6.4 Sensitivity analysis

This section discusses the impact of the input parameters on the results and aims at pointing out the ones with the most impact. As mentioned above, this is especially relevant taking into account the time frame of 2050 in this study, implying many uncertainties. The landscape is indeed likely to change over time. Commodity prices are subject to significant fluctuations, cost reductions might be over- or underestimated and more pressure could push up the CO_2 price. IT was already explained in Section 4.2.3 that this is investigated through a sensitivity analysis. In the next paragraphs, various parameters are considered separately after which their impacts are compared to each other.

Electricity cost

The electricity cost is the largest component in the OPEX of both scenarios. Therefore, it is useful to investigate its impact on the LCOH in more detail. Figure 6.6 shows the results of the sensitivity analysis. As expected, the impact on the OFF scenario's result is slightly higher (no injection in the grid), but the effect is very similar for both scenarios. Per 10 € decrease of the electricity cost per MWh, the LCOH decreases by about € 500 per ton or 0.5 €/kg. As of an electricity cost of €30/MWh, the ON scenario's LCOH gets competitive to the projected income of € 2,880 per ton H_2. For the OFF scenario, the electricity cost needs to be lower than 20 €/MWh. Similarly, the LCOH also declines when the efficiency goes up or when the amount of electricity consumed per kg H_2 decreases. Technical improvements are possible in the future but uncertain at the same time.

[1]taking into account a diesel consumption of 60 kWh/100 km and a diesel cost of 1 €/kg (including VAT and excluding excise duties).The resulting number only relates to the fuel consumption. The additional investment cost for a FCEV is not included. However, this disadvantage is expected to be decreased by 2050.

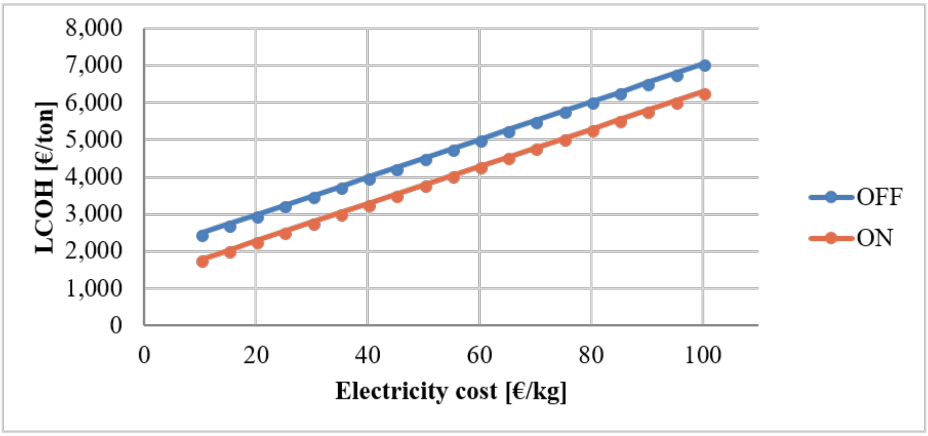

Figure 6.6: Sensitivity analysis of the electricity cost

Offshore equipment costs

For both CAPEX and OPEX in the OFF scenario, it is assumed that offshore installations are two times more expensive compared to onshore ones, given the additional expenses related to protection against the sea climate as well as the cost of installing and operating offshore. However, this factor can differ from case to case (e.g. shorter or longer distance) and moreover, new solutions might be developed facilitating offshore activities. Figure 6.7 shows the sensitivity of the LCOH to this additional cost. An offshore cost which is 200% of the onshore cost corresponds to the assumption used in this study. An 100% offshore costs in the figure means that an electrolyser offshore is just as costly as onshore (in terms of the LCOH). When this cost becomes smaller, the LCOH evolves more towards the ON scenario. However, only when the cost is below 120%, the OFF scenario surpasses the ON scenario in economic feasibility. So, in case of no additional cost, the OFF scenario's levelised cost would be lower because of the lower energy transport cost (via existing pipelines).

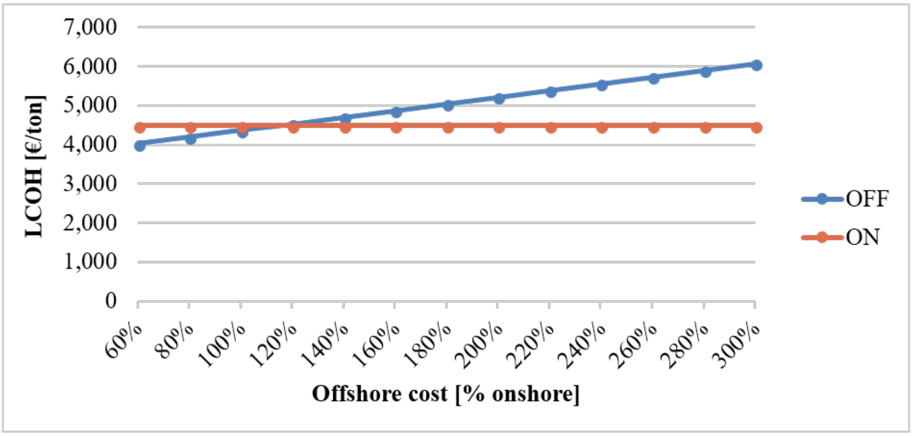

Figure 6.7: Sensitivity analysis of additional offshore cost

HVDC infrastructure costs

Another component which is subject to uncertainty is the HVDC infrastructure, including converters and cable equipment. For instance, the price of the cable equipment strongly depends on the copper price. Offshore converters could also experience cost reductions due to economies of scale because HVDC is becoming more widely applied. Figure 6.8 presents the sensitivity of the LCOH to this cost for both scenarios. It appears that the ON scenario is as cost-effective than the OFF scenario in case the HVDC cost is 180% more or almost three times the cost assumed before. However, such a big increase is rather unlikely.

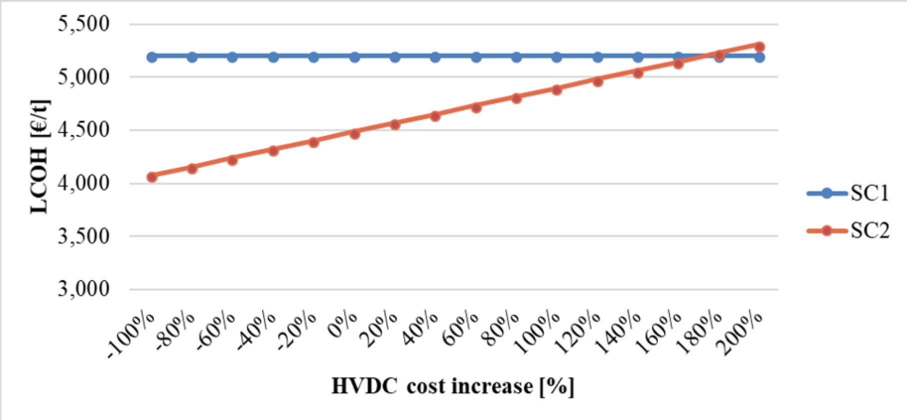

Figure 6.8: Sensitivity analysis of HVDC infrastructure costs

Impacting parameters of the OFF scenario

In order to investigate to which extent the considered parameters have an influence on the result, their impacts are compared to each other. Figure 6.10 includes five input parameters of the OFF scenario. The impact of the electricity cost on the LCOH is striking, shown by the steep slope. As concluded before, it represents a big part of the OPEX and on top of that, the OPEX is by far the biggest contributor to the yearly production cost. This extremely big impact also explains why other parameters do not have a strong effect on the result. The second biggest impact comes from the electrolyser cost which is the main component of the CAPEX. The additional cost because of operating offshore and the discount rate have a small impact, whereas the distance between the electrolyser and the existing gas pipeline barely has an impact as its curve is almost flat. The latter was expected because of the short distance (1 km) as the assumption that is started from.

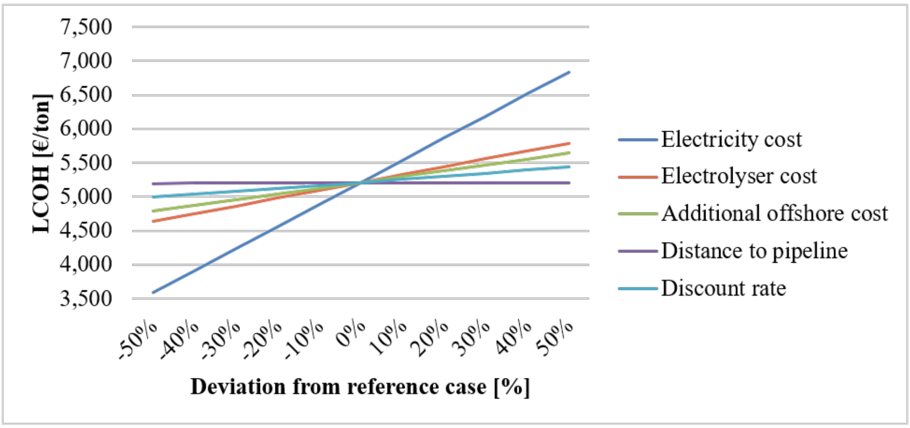

Figure 6.9: Sensitivity analysis of input parameters of the OFF scenario

Impacting parameters of the ON scenario

Figure 6.10 includes a sensitivity analysis of input parameters related to the ON scenario. Similar to the OFF scenario, the electricity cost clearly has the biggest impact, as indicated by the sleep slope in comparison with the other parameters' curves. The difference in impact with the other parameters is even bigger than in the case of the OFF scenario. The electrolyser cost still has the second biggest impact, before the HVDC cost. The effect of the distance to shore is very small, which can explained by the fact that the converters are the main contributors in the cost and are independent from the distance. The discount rate also has a rather small impact since this only relates to the CAPEX which represents a significantly lower share in the LCOH than the OPEX. So, it can again be concluded that the electricity cost is mainly determining the levelised cost.

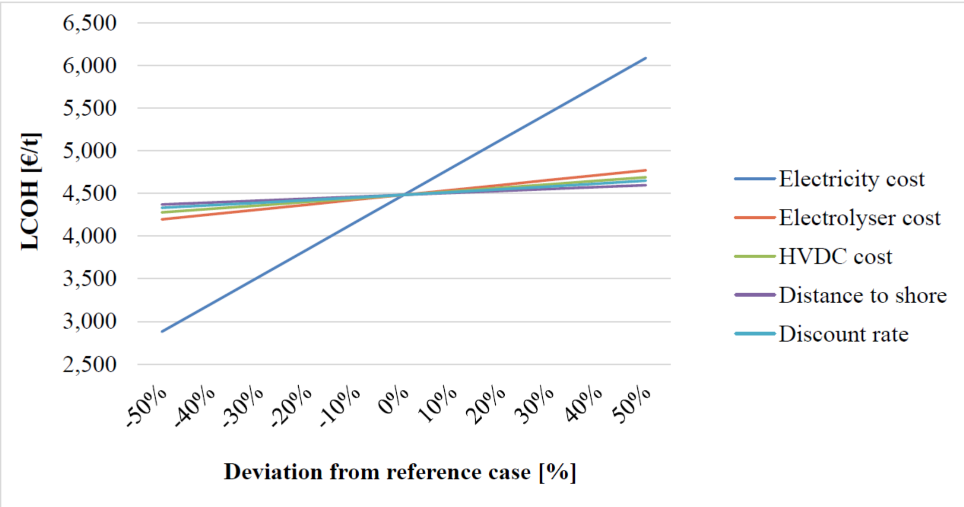

Figure 6.10: Sensitivity analysis of input parameters of the ON scenario

100% utilisation of electrolyser in the ON scenario

It was found earlier that the utilisation rate in both scenarios is only 43%. Now, an additional scenario (the ON 100% scenario) is created which is a variant to the ON scenario. Instead of the electrolyser being only fed by intermittent electricity from wind farms, a utilisation rate of 100% is assumed. This could be realised by also taking electricity from the grid which is not necessarily green. Since taking from the grid is not an option in the OFF scenario, this scenario is not contemplated here. The electricity cost per MWh stays the same though and consequently, the scenario can be used to investigate the effect of the utilization rate on the feasibility. Table 6.7 shows the LCOH of the ON 100% scenario compared to the one of the ON scenario. The LCOH decreased by 16%. The CAPEX is still the same but the OPEX increased a lot due to the electricity consumption. That explains why the LCOH decrease is not bigger.

	ON	ON 100%
Annuity [M€/year]	7,493	14,530
CAPEX	1,503	1,503
OPEX	5,990	13,027
H_2 production [ton/year]	1671,109	3,854,400
LCOH [€/ton]	4,483.7	3769.8

Table 6.7: LCOH in case of a 100% utilization rate

Access to market prices

So far, the cost of electricity per MWh has been equal to the projected cost by 2050, being 64 €/MWh. This is assumed since the wind farms are directly connected to the electrolyser. In the OFF scenario, there is simply no option of taking electricity from the grid. However, in the ON scenario with onshore electrolysis, there is access to the electricity market. Consequently, it is relevant to investigate an additional scenario where the electricity cost is equal the day-ahead market price which varies every hour. First, a scenario is looked at where the electricity is still coming from intermittent wind power (the ON MARKET scenario). Afterwards the LCOH in case of continuous electricity supply from the grid is investigated (the ON MARKET 100% scenario). Note that any electricity consumption from the grid for electrolysis is not counted in the forecast of the day-ahead prices. The impact of such a big consumer could be considerably big however, when the wind farm is still assumed, there is additional supply as well. Furthermore, the capacities of the systems are not optimised again under the new circumstances.

The results in both additional scenarios are presented in Table 6.8. It appears that both additional scenarios have a lower LCOH. When looking at the ON MARKET scenario , the lower levelised cost results from a lower cost related to the electricity consumption. It appears that variable market prices have a positive impact on the economic case. This can partly be explained by the fact that the yearly average of the market price is 52 €/MWh compared to 64 €/MWh in the ON scenario. However, in the sensitivity analysis of the electricity price discussed above, it appears that a fixed electricity cost of 52 €/MWh corresponds to an LCOH of 3882 €/kg H_2, which is higher than in the case of the ON MARKET scenario . This can be explained by the fact that the electrolyser is operating at the highest capacities at moments when there is a strong wind. On those moment, there will be a lot of wind power generation in general, possibly leading to lower market prices. So, the lower LCOH could be explained by the fact that the electrolyser is consuming the most electricity when its price is in a lower range. However, one needs to take into account that the electricity consumption from the grid is not counted in the forecast of the day-ahead prices.

The LCOH in the case of the ON MARKET 100% scenario with variable prices and 100% utilisation is even lower. This is due the fact that there is more hydrogen produced with the same investment cost.

	ON	ON MARKET	ON MARKET 100%
Annuity [M€/year]	7,493	6,108	12,224
CAPEX	1,503	1,503	1,503
OPEX	5,990	4,605	10,721
H_2 prod [ton/year]	1,671	1,671	3,854
LCOH [€/ton]	4,484	3,655	3,173

Table 6.8: LCOH results of additional market price scenarios

6.4.1 Externalities

In this section, external effects of the energy system are discussed.

First of all, the GHG emission savings by replacing current fossil fuel based demands are considered as positive externalities. Those can be divided into savings during the production (in contrast to grey hydrogen) and savings during the consumption. For instance in the transport sector, hydrogen would replace the combustion in diesel or petrol motors. Conversion by fuel cells only releases water. Green hydrogen can also be used to create heat where it replaces fossil fuels such as natural gas. On the other hand, the production side through electrolysis results in significant emission savings compared to grey hydrogen. SMR, as mentioned before, emits 10kg $C0_2$ per kg H_2 while green hydrogen production in an electrolyser has no GHG emissions. This was already covered in the hydrogen market price but can still be considered as an externality.

Another positive external effect is the fact that the potential of the North Sea with regard to wind energy is used without impacting the onshore main electric grid. In the ON scenario, the electricity is immediately converted into hydrogen as well without burdening the main grid. An alternative scenarios could be the electrification of the considered sectors in Chapter 6. In transport, FCEVs are replaced by BEVS. There are also electrification opportunities in the industry with for instance, power-to-heat instead of power-to-gas. High temperature heat pumps could be used for process heat, and electric furnaces could serve the steel industry. Hydrogen for feedstock is produced through on-site electrolysis. Heat in buildings could be supplied by heat pumps. In case of this scenario, the required electricity is also supplied by the same offshore wind power (24.5 GW) but it has to be transported via the main grid.

In view of this full electric scenario, it was put forward in Chapter 1 that grid integration costs related to offshore wind power are significant. This is confirmed by Delarue et al. [2016], investigating those costs for grid integration dividing them into three categories: grid connection, internal grid reinforcements and interconnections. In regard to grid reinforcement, next to the new Stevin HV line and substation already in place, the report states that the cable's capacity of the Stevin cable is not sufficient to connect the wind capacity foreseen by entso-e and Elia in the future scenarios with increasing RES. The grid integration cost related offshore wind energy for the Belgian system in 2030 scenarios are found to be in a range of 2.4-2.6 €/$\text{MWh}_{\text{intermittentRES}}$. Because the 24.5 GW wind farm produces 86.6 TWh per year, those costs would amount to 216 M€ per year (the OFF scenario). When deducted from the yearly production cost, the OFF scenario's

LCOH becomes 5,073 €/kg instead of 5,202 €/kg or a 2.5% decrease. In case of the ON scenario, a part of the surplus energy is injected into the grid which should not be counted. Accordingly, a production of 85 TWh corresponds to 214 M€ of grid integration costs. When again deducted, this leads to a LCOH of 4356 €/ton instead of 4,485 €/ton.

Next, using the existing offshore pipelines for hydrogen transport could have some positive external effects as well. When offshore oil and gas infrastructure is not used anymore, it is a legal obligation to decommission this infrastructure [Jepma, 2017]. As fossil fuels will be phased out in the future, the existing offshore gas pipelines would serve no purpose anymore and decommissioning will be required. The decommissioning phase of course entails costs. In the case of the OFF scenario where the existing gas grid is used for hydrogen transport, this gas grid would have a new purpose avoiding those decommissioning costs. However, the cost of removing gas pipelines is not considered as extremely high.

6.5 Summary

First, both energy systems, of the OFF and ON scenario, were dimensioned, and it appeared that the same capacities are economically optimal for both scenarios: 22 GW electrolyser capacity and 24.5 GW offshore wind capacity. In the detailed analysis, it became clear since the electricity cost is the main element in the levelised cost and is very similar for both scenarios. Nevertheless, the LCOH in the OFF scenario is, with 5.2 €/kg, 16% higher than in the ON scenario (4.5 €/kg). The main difference between the both scenarios is related to the investment cost since the additional expenses due to operating offshore are bigger than the cost of the HVDC infrastructure in the ON scenario. The OFF scenarios gets more cost-effective when the offshore costs are less than 120% of the onshore cost. However, the CAPEX has a rather small share in the levelised cost in comparison to the OPEX and consequently the impact of the CAPEX is limited. With regards to the economic feasibility, neither scenario corresponds to an LCOH that can be covered by the predicted hydrogen price of 2.88 €/kg (in the reference case). However, other factors might push the price up (or down), or it can be compared to other fuels as well such as diesel. Not only the hydrogen price but also various other parameters related to the cost are subject uncertainty. Additional scenarios showed that hourly market prices for electricity and a 100% utilisation rate might result in a cheaper hydrogen production.

The Role of hydrogen storage 7

Chapter 1 discussed the need for long-term storage in an energy system with increasing intermittent RES and which aims at being 100% renewable in the future. During summer, PV systems generate electricity surpluses, sometimes even leading to 'spilled electricity', while on the other hand, RES cannot cover the entire demand in winter due to 'dunkelflaute' periods. Long-term storage can be the solution and be the final piece in a fully decarbonising society. This chapter answers the third sub-question and investigates the need for long-term storage and the role hydrogen can play in this. A major advantage of converting electricity into hydrogen (power-to-gas) is the ability to store it. This fact enables opportunities but also various other possible technologies for storage are discussed and compared.

7.1 Need for long-term storage

100% renewable energy systems are often not considered as compatible with one of the main goals in energy policies, being security of supply (see Section 2.1). Especially with respect to the electricity supply, the instantaneous character of electricity requires thorough balancing. Elia [2017a] found that additional thermal capacity will be needed by 2040 in case of the *2040 RES scenario*. The 2040 RES scenario focuses on large-scale RES and includes 8 GW onshore wind, 8 GW offshore wind and 10 GW of solar PV. Those RES are complemented with combined heat and power (CHP), waste incineration, biomass and geothermal capacity. Note that CHP is not used for district heating (almost non-existing in Belgium) but rather in small-scale industrial installations. These are usually powered by natural gas or biogas. Adding realistic amounts of storage and interconnections to the 2040 RES scenario appeared to be not sufficient to avoid additional thermal capacity. The additional thermal capacity would be running on natural gas, causing considerable GHG emissions, which is not in line with the European goals towards 2050.

A solution could be to add more RES to the system. By 2050, the RES system evolves to 9 GW onshore wind power, 12 GW offshore wind power and 13 GW PV by extrapolating the 2040 RES scenario and taking into account maximum potentials. This can be called the *2050 RES scenario*. The same capacities as for the 2040 scenarios of CHP, incineration, biomass and geothermal (3.5 GW altogether) are used because of their limited potential.

In Figure 7.1, the 2050 RES scenario is plotted on a weekly basis without any additional thermal capacity, storage or interconnection capacity. First of all, one can notice a clear trend in the load (demand), with a significantly lower demand during summer than during winter. The total yearly estimated demand is estimated 94 TWh. Next, as expected, electricity generated by solar PV is much higher during summer. The yield from wind power is a bit higher in winter but what is more striking, is its variability between weeks. This results in massive surpluses in some weeks and gaps in other weeks. An adequate security of supply is clearly not guaranteed here, even though the electricity produced amounts to 109 TWh which is 15 TWh more than the yearly demand.

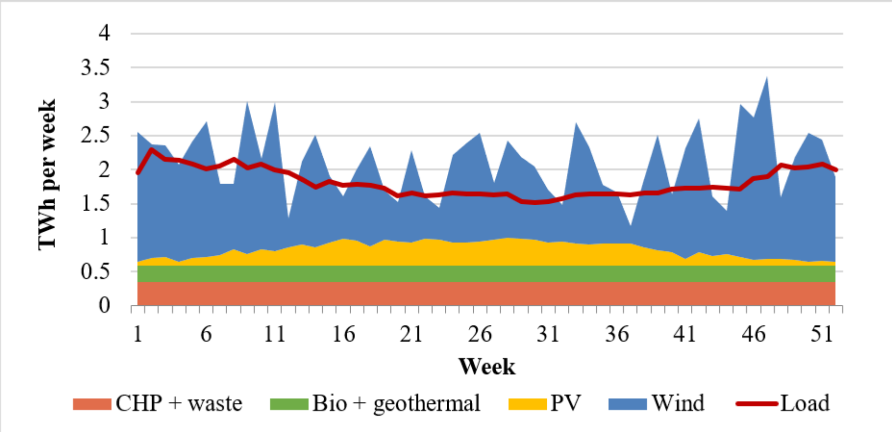

Figure 7.1: Electricity generation and load in the 2050 RES scenario on a weekly basis

The assumed storage capacity in the 2040 RES scenario is also extrapolated to 2050 and added to the 2050 system. This includes both battery storage (stationary and vehicle-to-grid (V2G)) and pumped storage. Altogether, this corresponds to 5.1 GW charging/discharging capacity and a storage content of 14.9 GWh. Interconnection capacity is not included in the scenarios because of the related reliability and the hourly availability in the interconnected countries is beyond the scope of this study.

Table 7.1 shows the yearly surpluses and deficits for the 2040 and 2050 RES scenarios. The surpluses are more than twice as high in the 2050 RES scenarios while the deficits are only reduced by 28%. This can be explained by the fact that at very windy and sunny moments, additional capacity just results in more excesses whereas during dunkelflaute periods, the yield per GW installed is very small or even zero and consequently, additional RES capacity does not have a big impact. So, it can be concluded that by adding more RES and proportionally more storage, the system is still far from balanced and meeting the demand.

	2040 RES	**2050 RES**	**% difference**
Surplus [TWh/year]	12.7	26.7	+110%
Max. surplus [GW]	13.6	19.3	/
Deficit [TWh/year]	17.6	12.6	-28%
Max. deficit [GW]	11.0	10.9	/

Table 7.1: Surplus and deficit in RES scenarios

Considering the trend in Table 7.1, It can be interesting to look at how those numbers look with higher RES penetrations. In Figure 7.2, this evolution is shown with increasing capacity of offshore wind power. With respect to excess electricity (in blue), a slow growth can be noted for small capacities (2-4-6 GW) after which the increase becomes bigger. The opposite appears concerning the residual load (in orange), where in the lower capacity range, additional offshore capacity results in significant decreases in the residual load while diminishing returns can be found for bigger capacities. Even with very high wind capacities, the residual load does not tend to zero.

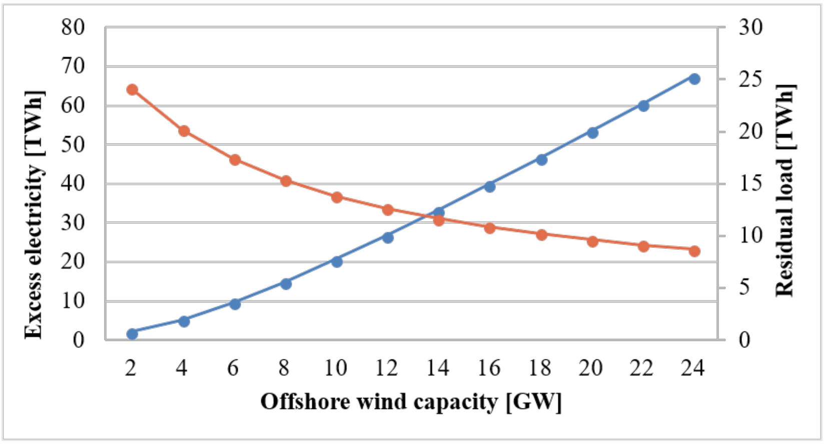

Figure 7.2: Spilled energy and residual load with increasing wind power in the 2050 RES+ scenario (blue = excess electricity; orange = residual load)

In order to have more insight in the hourly excesses and gaps, a winter and a summer week are shown in Figures 7.3 and 7.4 respectively. The residual load and excess electricity of the week in TWh are mentioned in the figures. Negative colored areas correspond to charging of the storage.

A winter week with a high residual load was selected so as to investigate the gaps. The maximum hourly gap is 9.6 GW. As typical for dunkelflaute periods, several days with low wind speeds succeed each other. For such long periods, the included storage is not sufficient. As shown in Figure 7.3, storage reduces the residual load for a few hours but the storage is empty afterwards and cannot contribute in the supply for several days, until the wind starts blowing again. A solution needs to be found that can deliver electricity for longer periods and at a sufficiently high power.

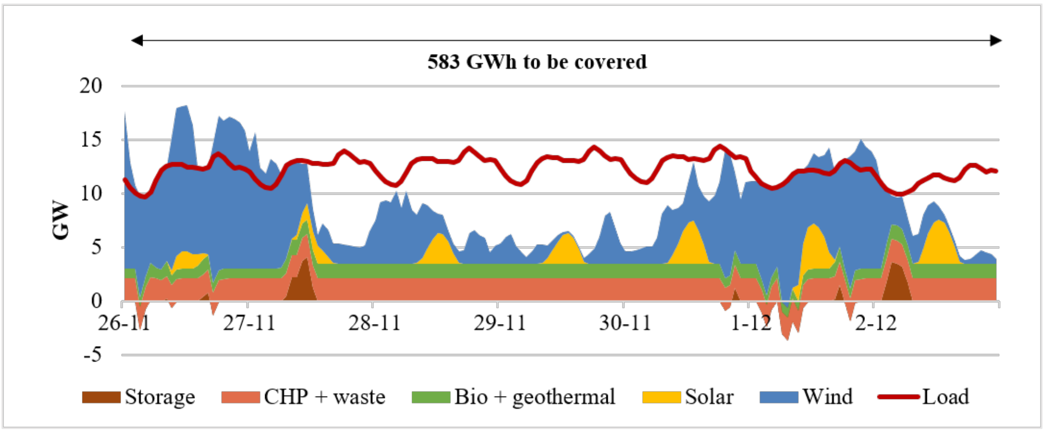

Figure 7.3: Winter week in the 2050 RES+ scenario

With respect to the summer week, massive electricity excesses are found. The maximum excess in this interval is 19.3 GW. At some moments, three times more electricity is generated than needed. The storage is not able to absorb such big amounts of electricity and there is still a lot of electricity that cannot be evacuated. The figure shows that the excesses occur consecutively for several days. The total yearly excess electricity in the 2050 RES+ scenario was already estimated to be 27 TWh. With no other solutions, big amounts of solar or wind power would be curtailed. It should be noted that those excesses do not only occur in summer but they are possible along the whole year, due to the variability related to wind power.

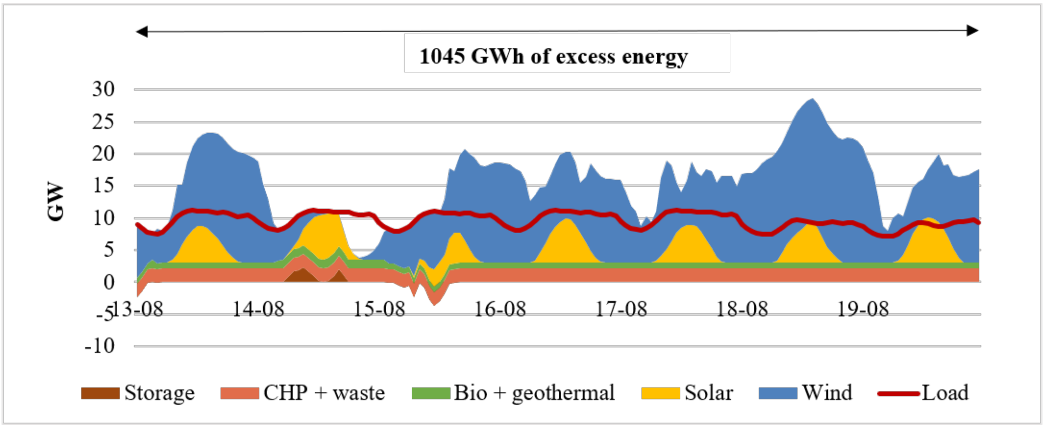

Figure 7.4: Summer week in the 2050 RES+ scenario

The excess electricity, 27 TWh, is more than twice as big as the residual load, being 13 TWh. However, without any further measures, those excesses cannot contribute in any way in reducing the gaps. The gaps can be compensated by either conventional thermal capacity (most likely fossil-based), interconnection capacity or another solution has to be found which absorbs big amounts of surpluses and which can fill long lasting gaps. However, the maximum residual load in a year is 10.9 GW which is still much higher than the maximum simultaneous imports of 6.5 GW concluded by Elia [2017a]. Even when this import capacity would always be available, which is very unlikely, there would still be an unmet demand for 467 hours.

Since the society will be moving away from fossil fuels, opportunities are opening up to niche technologies. Storage is considered in order to solve both grid-balancing issues, over- and undersupply of electricity at once. It appeared in Figures 7.3 and 7.4 that long consecutive periods of excess and residual load might occur. The fact that longer periods need to be covered leads to *long-term* or even *seasonal storage*. In the next section, possible solutions for long-term storage are investigated.

7.2 Techno-economic analysis of long-term storage

To find an appropriate solution, various storage possibilities are considered. Some were already brought up in the previous section such as batteries and pumped storage. Those will be discussed in more detail, together with other other technologies. Afterwards, the economic feasibility is assessed.

7.2.1 Storage technologies

Different energy storage technologies exist which may be characterised by their capacity, power and response time. The capacity refers to the amount of energy a technology (in kWh) can typically absorb. The power (in kW) indicates how fast a storage unit of the technology concerned can be charged or discharged. An overview of the currently most common technologies is given in Figure 7.5. The applicable technologies are positioned depending on the minimum discharge time as well as the needed storage capacity. So, for instance, flywheels can discharge very quickly but are typically only suitable to small capacities. Power-to-gas seems suitable for large-scale storage. Because the energy should be stored for longer periods in the 2050 RES scenario and should deliver electricity for a longer period of time, a large capacity is necessary. In the next paragraphs, the considered technologies are explained in more detail.

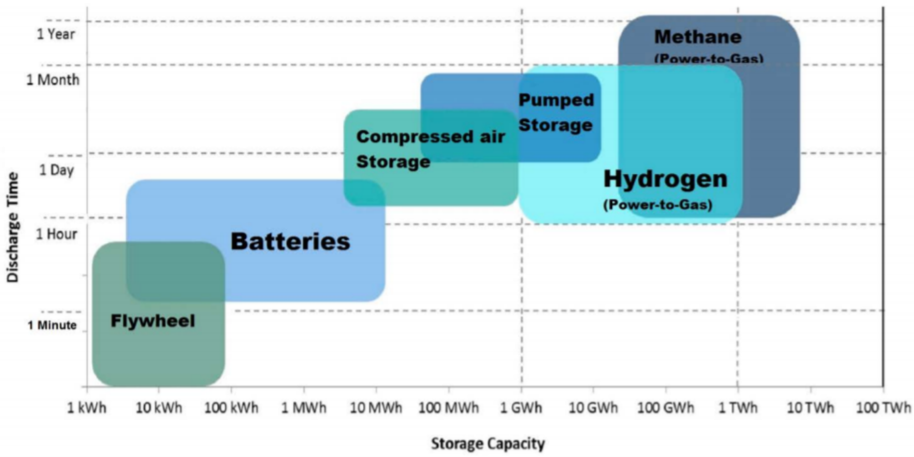

Figure 7.5: Energy storage technologies compared [EERA, 2017]

Larger **batteries** (lithium-ion) in the MWh range are technically feasible and are appropriate for short to medium term storage (minutes to hours). Lithium ion batteries are considered because of their technical specifications (energy and power density, cycle and calendar life, and cost) and future potential. They can play a role in grid balancing and managing the daily variability of renewables, e.g. solar energy day-night cycles. The high round-trip efficiency of about 90% and the fast response time are big advantages. However, they are not suitable to long-term storage because of self-discharge and the high costs [Abdon et al., 2017]. Another disadvantage is the uncertain lifetime as the degradation is highly dependent on the charging behavior (frequency and power of cycles) and external circumstances. An exception is the redox-flow battery, consisting of two electrolyte tanks, which does not experience self-discharge and has a longer and more certain lifetime. These are suitable for energy storage up to 2 MW and during hours to days so they can deal with weekly fluctuations of RES. [FCH JU, 2015]

Compressed air energy storage (CAES) refers to storing electricity in the form of potential energy of air. Air is compressed by means of electricity when the electricity demand is low, stored underground, and expands in a gas turbine when electricity is needed. However, another fuel (fossil nowadays) is required for additional heat in the expansion process. CAES is suitable to large-scale applications but is characterised by low efficiencies (42-54%) and a high cost. Only a few installations exist in the world. New CAES technologies are being developed where thermal storage is included next to the air storage, so as to make supplementary fuels unnecessary, but those are still in an experimental phase. [Abdon et al., 2017]

Pumped hydro energy storage (PHES) is another storage technology for large-scale storage, where energy is stored in the form of potential energy of water. The principle is similar to CAES [EERA, 2017]. When the electricity excesses occur, water is pumped to an upper reservoir after which the water may be released downwards to power a turbine when there are deficits. PHES is currently providing the largest storage capacity worldwide. However, as a considerable difference in height is required, the potential is limited by topographical conditions. The environmental impact might also be an issue. As mentioned in the previous section, Belgium's energy system already includes a PHES capacity of 1.3 GW (Coo 1 & 2, Plate-taille) and there is still a potential of 0.6 GW (Coo 3) [Elia, 2017a].

Next, after converting electricity into hydrogen through electrolysis, the hydrogen can be re-electrified again. This is the **hydrogen-to-power** or power-to-power (P2P) pathway that was shown in Figure 5.2. Re-electrification can be achieved in a fuel cell or a gas turbine, either an open cycle or closed cycle gas turbine (CCGT or OCGT). Fuel cells are rather used for smaller applications in FCEVs or fuel cell micro CHP, while gas turbines are usually large-scale power plants. Due to two conversions (electrolysis and re-electrification), hydrogen storage is characterised by low round-trip efficiencies of 30% and 35% for fuel cells and gas turbines respectively. However, this efficiency would be higher in case the released heat could be used in district heating. The storage itself of hydrogen can be done in tubes, vessels or salt caverns. The storage in salt caverns is the most-cost effective for large-scale storage and the low cost could partly compensate for the low efficiencies reached. Injection and withdrawal capacities are high. [FCH JU, 2015] As mentioned earlier, Belgium already counts a 680 million m^3 gas storage facility in a salt cavern that is currently occupied by natural gas. In the future, this facility could be used for hydrogen and/or synthetic methane storage. However, adjustments need to be done to the surface facilities because of the different properties of hydrogen. It could maximally store 61 kton[1] or 2 TWh (LHV) of hydrogen. This high storage capacity is suitable to longer periods of residual load and excess such as the summer week discussed in the previous section where the excesses amount to 1.045 GW in one week.

A representation of such a system is given in Figure 7.6. [Danish Energy Agency, 2018b]

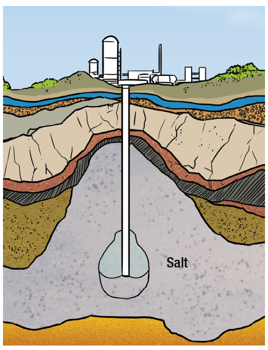

Figure 7.6: Hydrogen storage system with salt cavern [Energy Infrastructure, 2018]

[1] The volume of 680 million m^3 can be fully used

Abdon et al. [2017] concluded that power-to-gas-to-power and PHES are the only technologies that can be considered as fossil-free long-term storage solutions. This is confirmed by the description of the technologies. Considering the limited potential of PHES in Belgium, it is not included in the further investigation.

7.2.2 Economic feasibility of P2P

The rise of renewables delivering electricity at an almost zero marginal cost has serious implications for other electricity supplying units. Any additional capacity, either thermal capacity or storage solutions, is only complementing to the intermittent RES and has a low utilisation factor. This is also the case for long-term storage such as hydrogen storage. Specifically for long-term storage, less annual cycles occur compared to short-term storage. As for conventional thermal capacity, gas turbines or fuel cells are needed with sufficient power and consequently with low utilisation. This limits the economic feasibility of such storage facilities.

A load curve of the residual load in the 2050 RES scenario is given in Figure 7.7. The figure shows that there is residual load for less than 4000 hours. The peak residual load is 10.7 TWh but the residual load surpasses 8 GW only for 165 hours. For a plant with a capacity equal to this peak capacity o 10.7 GW, the utilisation factor would be 14%.

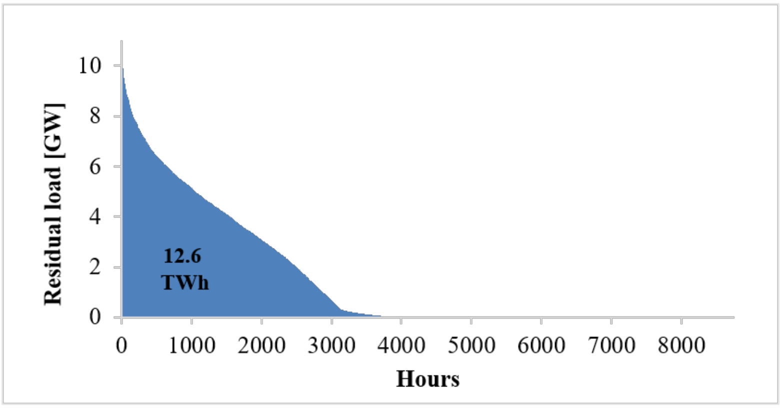

Figure 7.7: Load curve of the residual load in the 2050 RES scenario

When hydrogen is used for storage, the production of hydrogen is still a part of the system but the focus is rather on the grid-balancing and electricity aspect. The additional cost components due to storing the electricity are electrolysis, storage and re-electrification of hydrogen. As was found in Part 2 of the analysis, the electricity cost has an extremely high impact on the economic feasibility of hydrogen production. Rather than the hydrogen price, the benefit from electricity injecting now needs to cover the cost. As explained in Section 4.2.4, hourly electricity prices forecasted for 2040 are used in this analysis. This variability means that the economic case of one storage cycle is highly dependent on the moment of charging and discharging or in this case, the moment of electrolysis and re-electrification in fuel cells or a gas turbine. Because the aim of hydrogen storage is to fill parts of the residual load and to absorb excesses, both extreme events, extreme electricity values are expected in both directions. Excesses lead to very low and even negative prices while deficits may result in very high prices (over 150 €/MWh).

Similar to Part 2 of the analysis, the levelised cost method is used so as the determine the cost that has to be covered by the just mentioned electricity value when re-electrificated.

With respect to conversion to hydrogen, the electrolyser is dimensioned similarly as in Part 2, by minimizing the LCOH (explained in Section 4.2.4. If the plant would be dimensioned on the peak electricity excess of 19.3 GW, the last GWs would be rarely used with a low utilisation factor (16%) as a consequence. The LCOH minimisation results in a capacity of 11 GW which is much lower as 19.3 GW but 1 TWh out of 27 TWh cannot be converted anymore and is curtailed. The corresponding utilisation factor is 27% which is still much lower than 43% in the ON scenarios. Nevertheless, the resulting LCOH is -37.1 €/ton (or -1.1 €/MWh) which is much lower than the LCOH of the ON scenarios, 4,484 €/ton. This extremely low and even negative cost is fully due to the cheaper electricity cost when using market prices, where the total yearly electricity cost is a negative amount. It implies that the electrolyser often operates at moments with negative prices and moreover, that there are a lot of moments with negative prices. When analysing the Elia 2040 values, it appears 24% are negative. The minimum value in the forecasted prices is -71 €/MWh.

The levelised cost for storing and re-electrification is calculated for a system existing of a salt cavern and a gas turbine. The same assumptions about the lifetime (20 years) and discount rate (4%) are used. The cost assumptions are given in Table 7.2. The hydrogen is assumed to be stored in an existing salt cavern in Loenhout. The costs related to the cavern itself are negligible, but compressors (above ground) are required. The 2 TWh storage content is sufficient to cover five days without any input from intermittent RES[2]. However, other storage thanks currently used for natural gas are considered available as well. A gas turbine is opted for since its suitability to large-scale installations. More specifically, an OCGT is used taking into account its lower investment cost (compared to CCGT) and the low utilisation factor, even though it has a lower efficiency.

Parameter		**Source**
Salt cavern storage		
CAPEX compression [€]	30,000,000	Danish Energy Agency [2018b]
OPEX compression [€]	900,000	Danish Energy Agency [2018b]
OCGT		
Efficiency [%]	45%	Danish Energy Agency [2018b]
CAPEX [€/MW]	520,000	Danish Energy Agency [2018b]
Fixed OPEX [€/MW]	18,000	Danish Energy Agency [2018b]
Variable OPEX [€/MWh]	4	Danish Energy Agency [2018b]

Table 7.2: Cost assumptions for hydrogen storage

The levelised cost of storage in the salt cavern is 1.0 € per MWh of electricity produced. The LCOE for electricity produced in a gas turbine from hydrogen is 49.9 €/MWh. The 14% utilisation rate is taken into account here. The total levelised cost of reinjecting 1

[2]The daily demand is calculated by subtracting the dispatchable production (CHP etc.) from the average daily demand (out of the yearly demand of 94 TWh). This results in 0.17 TWh/day. After incorporating the gas turbine efficiency of 45%, it is concluded that 2 TWh can cover about 5 entire days.

MWh of electricity is equal to 46.4 €/MWh, which is less than the gas turbine's LCOE due to the negative LCOH.

A break-down of the total levelised cost is shown in Figure 7.8. Note that this cost of hydrogen production cannot be compared to the LCOH calculated before as more than 1 MWh of hydrogen is needed for the production of 1 MWh of electricity, due to energy losses in the gas turbine (45% efficiency). It is clear that the cost related to the re-electrification in the gas turbine is responsible for the biggest part in the LCOE. The conversion from electricity into hydrogen through electrolysis entails a negative cost of -2.5 €/MWh and brings down the total LCOE. The storage itself only represents a very small part of the cost.

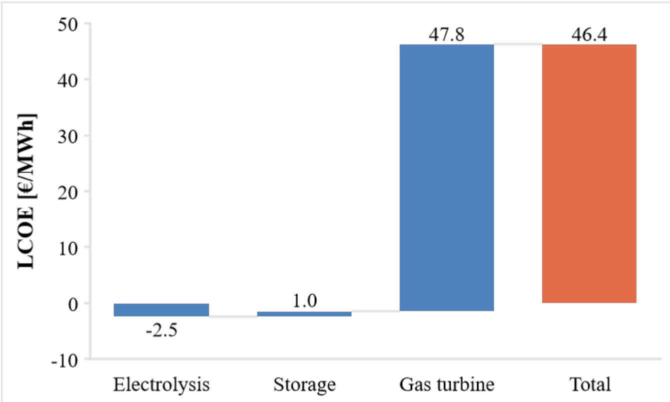

Figure 7.8: LCOE breakdown of the hydrogen storage system

So, in order to make the hydrogen storage system economically feasible, the total cost per MWh has to be covered by the benefit due to injecting. In this case, this benefit should be at least 46.6 €/MWh. Given that about 58% of the market prices are above 46 €/MWh, such a situation is not unlikely. Even though the high share of negative values, the average forecasted price is higher than the average in 2017 (51.9 against 44.6 €/MWh). Hence, one can conclude that in case of the used market prices, hydrogen or P2P is economically feasible and a viable solution in the integration of intermittent RES.

Nevertheless, one should keep in mind that the electricity cost is a very determining element in the LCOH and in the eventual LCOE, but it is uncertain if the actual market prices will be in the same range and will contain as much negative values. Moreover, adding P2P facilities of such a size would also have an impact on the prices. Therefore, the LCOE has been additionally calculated in case of fixed prices. In this way, insight in the required spread between the cost of consuming electricity and the benefit of re-electrification can be obtained. Different combinations of electricity consumption cost and electricity benefit with the corresponding value (benefit of reinjecting minus cost of consumption) are given in Figure 7.10. Cases with a positive value are marked in green. For instance, for an electricity consumption cost of 20 €/MWh, the reinjection benefit needs to be at least 200 €/MWh (or a spread of 180 €/MWh) to get a positive value. To compare with the 2040 values, 25% are above 101 €/MWh but only 1% are above 200 €/MWh. It can be concluded that either the electricity cost needs to be extremely low, or even negative, or the electricity benefit needs to be extremely high.

Given the high impact and uncertainty of the electricity price, it is relevant to look at the impact of the technical performance of electrolysis. Therefore, a sensitivity analysis is done with changing electrolysis efficiencies. As expected, Figure 7.9 shows that the LCOE of the electricity to be injected is decreasing with higher efficiencies. The efficiency assumed in the analysis is 50 kWh/kg H_2 corresponding to 67%. It appears that with a 1% efficiency increase, the LCOE decreases by about 2 €/MWh or with 1%.

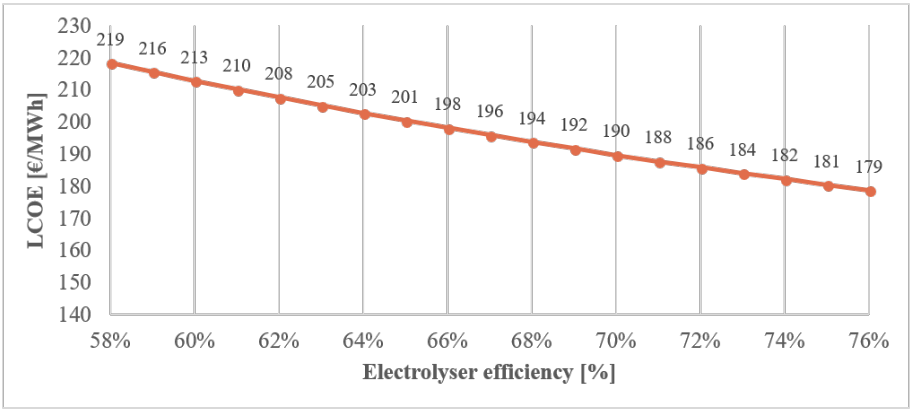

Figure 7.9: Sensitivity analysis of impact of electrolysis efficiency on the LCOE with a fixed electricity cost 20 €/MWh

Finally, it is also worthwhile to point out that hydrogen storage could also be used for other grid-balancing applications such as for the primary energy reserves (frequency control reserve (FCR)). This is currently being tested in Hobro (Denmark) in the framework of the EU HyBalance project with a 1 MW electrolyser. However, there is no P2P involved as there is only electricity taken from the grid and not delivered. (See Appendix A.4)

Value [€/MWh]	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200	210	220	230	240
-60	120	130	140	150	160	170	180	190	200	210	220	230	240	250	260	270	280	290	300	310
-50	87	97	107	117	127	137	147	157	167	177	187	197	207	217	227	237	247	257	267	277
-40	53	63	73	83	93	103	113	123	133	143	153	163	173	183	193	203	213	223	233	243
-30	20	30	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200	210
-20	-13	-3	7	17	27	37	47	57	67	77	87	97	107	117	127	137	147	157	167	177
-10	-47	-37	-27	-17	-7	3	13	23	33	43	53	63	73	83	93	103	113	123	133	143
0	-80	-70	-60	-50	-40	-30	-20	-10	0	10	20	30	40	50	60	70	80	90	100	110
10	-113	-103	-93	-83	-73	-63	-53	-43	-33	-23	-13	-3	7	17	27	37	47	57	67	77
20	-147	-137	-127	-117	-107	-97	-87	-77	-67	-57	-47	-37	-27	-17	-7	3	13	23	33	43
30	-180	-170	-160	-150	-140	-130	-120	-110	-100	-90	-80	-70	-60	-50	-40	-30	-20	-10	0	10
40	-213	-203	-193	-183	-173	-163	-153	-143	-133	-123	-113	-103	-93	-83	-73	-63	-53	-43	-33	-23
50	-247	-237	-227	-217	-207	-197	-187	-177	-167	-157	-147	-137	-127	-117	-107	-97	-87	-77	-67	-57
60	-280	-270	-260	-250	-240	-230	-220	-210	-200	-190	-180	-170	-160	-150	-140	-130	-120	-110	-100	-90

Electricity injection benefit [€/MWh]

Electricity cost [€/MWh]

Figure 7.10: Value of reinjecting 1 MWh of electricity for different electricity prices based on 10.7 MW reinjection

7.2.3 Alternatives

This chapter has been focusing on storage but however, one should keep in mind that there might be also other competing niches that deal with the integration of intermittent RES. They might all plan to take their share of the excesses, deficits or even the storage in the salt cavern.

Electricity for heating was earlier in this report considered as a competing technology to hydrogen for heating, and at the same time it is also seen as a competing technology to hydrogen for grid-balancing. As part of the smart energy systems proposed by Lund [2014] (see Section 3.1), the electricity grid and thermal grid are to be coupled. By using electricity for heating purposes, energy can be stored in the form of heat which is cheaper and more efficient than electricity storage. Its use for grid regulation is also pointed out. This concept is called *power-to-heat*. Either individual heat pumps or large-scale heat pumps in district heating are considered here for storing excess electricity. Lund et al. [2018] showed the socio-economic benefit of heat pumps in district heating in Denmark (a country with high shares of wind power) and Lund [2018] proclaims smart energy systems with integrated district heating (DH) have a lower cost than smart electricity grids (incl. individual heat pumps) requiring infrastructure expansion and additional storage. However, individual heat pumps are the most likely option in Belgium since heating is mainly individually organised. This niche is supported by the Belgian regional governments and grants are given [InfoWarmtePomp, 2018]. However, the existing small-scale heat pumps are not yet operating in a smart way. There is the potential of interaction with the needs on the electricity grid but this is still easier to manage with centralised DH plants. New DH plans in Flanders are planned which might offer opportunities. Nevertheless, note that power-to-heat only offers a solution in dealing with excesses and not in meeting any electricity deficit.

Another option is additional investments in interconnection capacity. The EU promotes cross-border trade and competition in electricity generation across the EU and aims at an *Energy Union* with a *single market*. However, this market is not yet trusted to provide mutual electricity security. Therefore, member states have moved to a more local view on ensuring security of supply, even at a higher cost, for instance by means of capacity remuneration mechanisms. Likewise, Belgium introduced strategic reserves in 2014. This trend is also partly legitimate: if interconnected countries are relying on a similar energy mix, they face surpluses and deficits at the same moments. This is the case for the Netherlands and Germany which also focus on wind energy and have similar weather conditions [RTL Nieuws, 2018] [van Wijk, 2018]. Elia [2017a] states peaks are not simultaneous, but on the other hand, there are hours where there is not enough production available abroad due similar demands and weather patterns influencing the import potential of Belgium.

Increased flexibility in the demand was already proposed for the integration of RES in Chapter 1. Demand-side management (DMS) may play a role for short periods (a few hours) but it is not sufficient. Shifting of the consumption is limited and *"even if the demand would be completely flattened, the need would remain"* [Elia, 2017a]. Demand shedding can also help but it has to be continued for multiple days in order to be effective. This is confirmed by Kwon and Østergaard [2014] assessing the potential of flexible demand by 2050 where the Danish electricity system serves a case. Flexible demand in both the 2h time frame and 24h time frame does not have a significant impact on the energy system performance. It is concluded that 25% of the classic electricity demand within a month would be necessary, which is highly unlikely.

As put forward before, synthetic natural gas can be produced as well and so their might not be full access to the considered salt cavern.

7.3 Integrated approach: Coupling with the energy system in Part 2

So far, the issue of grid-balancing has been considered rather separately from the previous chapters dealing with green hydrogen as an energy carrier and as fulfilling the demand of hydrogen outside the electricity grid. In this section, the proposed solution for grid-balancing, being hydrogen storage, is added to the energy system of Part 2 of the analysis. The ON scenario is continued with as it has access to the main grid and it appeared to be the most cost-effective . The new scenario is called the *ON P2P scenario*. Given that the electrolyser is only dependent on the offshore wind power output and that the utilisation rate is only 43% as a consequence, there is still spare electrolysis capacity. This spare capacity can be used for absorbing excesses and could decrease the required capacity of the electrolyser for P2P purposes. This may affect the economic feasibility of both producing green hydrogen and hydrogen storage. The investment cost of the system in the ON scenario can be allocated to a bigger production and investment costs can be avoided in the P2P system. Therefore, the impact on the economic feasibility of both purposes is studied.

During hours of spare capacity, the capacity of the electrolyser in the ON scenario is filled with excesses on the grid. Taking into account that those excesses are mostly caused by intermittent RES, the additional electricity consumed by the electrolyser can be considered as 100% renewable electricity. The fact that is taken from the grid also means that the electricity cost is different. Similar to the previous section, 2040 hourly prices forecasted by Elia are used. Nevertheless, the electricity input from the offshore wind farm used for the initial hydrogen production still costs 64 €/MWh.

The results show that the utilisation factor of the 22 GW electrolyser increases from 43% to 52%. This is also shown visually in Figure 7.11. The electrolyser is operating 113 hours more and the load is also higher during the operating hours. This increased operation may have an impact on the economic feasibility, as more hydrogen is produced with the same installed capacity.

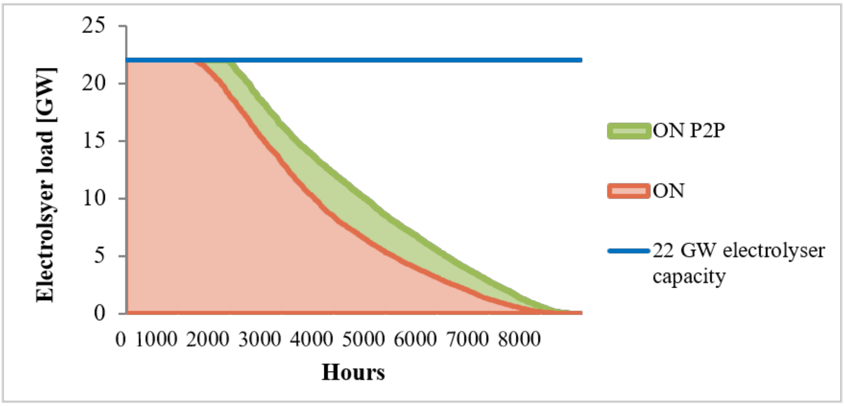

Figure 7.11: LCOE for different electricity costs and benefits

Thanks to using the electrolyser in the ON scenario for both purposes, the capacity of the electrolyser for grid-balancing purposes can be reduced by 1.6 GW compared to the separate P2P scenario. The new capacity is 10.4 GW instead of 12 GW. There is still a peak excess of 16.4 GW (instead of 19.3 GW). This is due to simultaneity between excesses on the grid and offshore wind power since the electricity system in the 2050 RES scenario also includes a lot of offshore wind power. As a consequence, the spare capacity is not sufficient to absorb more excesses.

The uncoupled and coupled scenario are presented in Figure 7.12. Each row represents an electrolyser. First, the uncoupled initial scenarios are shown with the capacity, utilisation factor, hydrogen production and the eventual LCOH for each electrolyser. The system cost in case of separate systems (explained in Section 4.2.4) amounts to 7,473 M€/year.

The lower part of Figure 7.12 shows the results of the new integrated ON P2P scenario. As can be noticed, a part of the hydrogen with P2P purposes is now produced at the ON electrolyser. Whereas the utilisation factor of the ON electrolyser increases, the one of the P2P electrolyser decreases from 27% to 10%. Only the excess electricity that is left after filling the spare capacity of the ON electrolyser is available to the P2P electrolyser. This can also be noticed in the decrease of the hydrogen production at the P2P electrolyser.

In order to have insight in which costs are caused by which purpose, the costs are allocated to the production for meeting the hydrogen demand on one hand, and to the production for storage purposes on the other hand. The allocation is done according to the amount of hydrogen produced as motivated in Section 4.2.4. Thus, the ON P2P part for storage bears the investment cost to a lesser extent and only incorporates the electricity it consumes (at the market price). Next, one can also notice that the LCOH at the ON electrolyser for demand purposes has decreased compared to the initial ON scenario. Hence, the electrolysis to meet the demand benefits from the integration. The LCOH for P2P is considerably higher than in the initial P2P scenario which is due to the low utilisation of the P2P electrolyser. When split, the hydrogen produced at the P2P electrolyser has an LCOH of 1783 €/ton while the hydrogen for P2P at the ON electrolyser has an LCOH of -384 €/kg. The shown 387 €/ton is a weighted average.

The total system cost of these three components amounts to 7,362 M€/year which is 111 M€ less than in the separate scenario. Thus, one can conclude that it is economically beneficial for the society to couple the two different hydrogen purposes. The difference is rather small but considerable electrolyser capacity can be avoided.

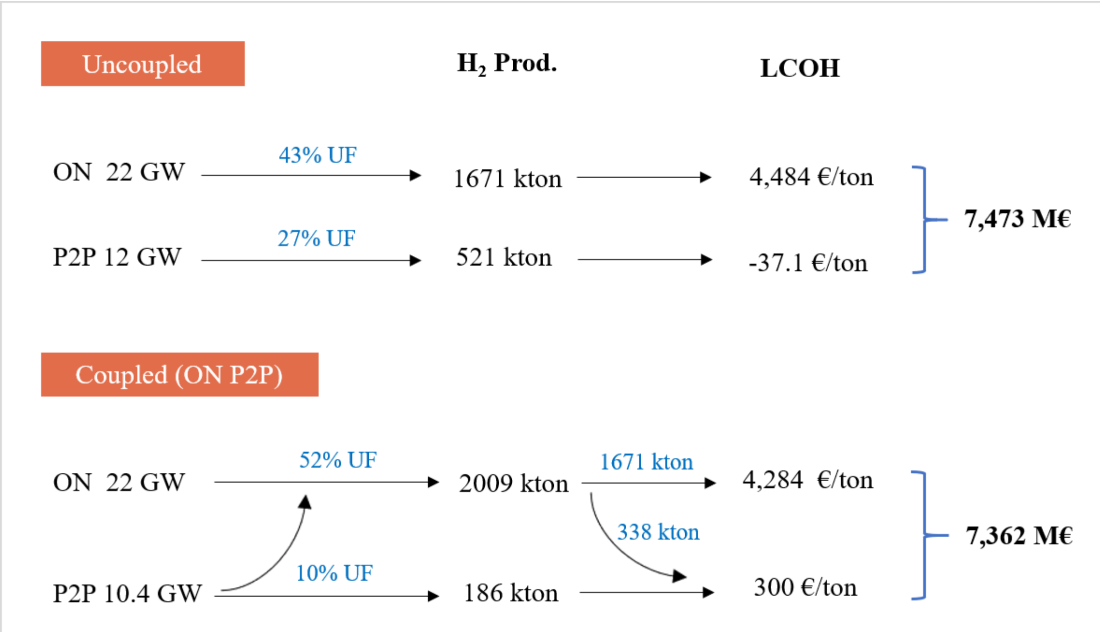

Figure 7.12: Uncoupled versus coupled system cost

7.4 Summary

The first part of this chapter showed that there is a clear need for long-term storage. Even with high RES capacities in the 2050 scenario, there is still a considerable residual load, being 13 TWh per year. This is 14% of the forecasted yearly demand. At the same time, this RES cause massive excesses, being 27 TWh per year. The system is not balanced and needs complementary solutions. It appeared hydrogen storage (power-to-gas) is the most suitable to the Belgian energy system because it can store big quantities of energy for a long time and it is technically feasible. The existing salt cavern in Loenhout could be used for hydrogen storage (2 TWh). Next, the economic feasibility was assessed, and since forecasted market prices are used which include many low (even negative) and high prices, a positive economic case is possible. A very low, even negative LCOH (-37.1 €/ton) is found. The levelised cost of reinjecting 1 MWh of electricity amounts to 46.6 €/MWh, which is likely to be covered at moments of residual load. Nevertheless, when looked at needed spread, it appears the P2P system is only positive with very low electricity costs and high electricity benefits from injection.

In the last part of this chapter both the use of hydrogen in long-term storage (P2P) and fulfilling the green hydrogen demand are combined into one system. It appears the total system cost for society is 111 M€/year lower if the electrolyser in the ON scenarios of Part 2 is also used for grid-balancing purposes. The CAPEX in the ON scenario can be allocated to a bigger hydrogen production and less electrolyser capacity is needed for P2P purposes.

Discussion 8

This chapter encompasses a more thorough discussion of the methods and theories and how they influence the performed analysis and its outcome. Moreover, the results are put in a wider context. Thereby, three topics are addressed: offshore electrolysis, the choice for offshore wind power and the impact of the project on the entire Belgian energy system. Next, the regulatory framework is dealt with as it appears to be an essential element in the implementation of the project. Across the chapter, reflections are made with regards to the report's limitations. Lastly, suggestions for further work are given.

8.1 Methods

The *socio-economic perspective* appears to be appropriate for solutions at country level. It entails the wider perspective that is needed to answer the research question as it is not about profits (business-economic) but about a cost-effective solution for society. This is continued in the last part of the analysis where the different energy systems are integrated. The system cost is the base of comparison which would not be possible when both systems are approached from a private viewpoint.

The *levelised cost* is used as an economic metric throughout Part 2 and 3. It has the advantage that it is very intuitive and therefore easy to understand. However, the method also has limitations. As prescribed by [Bloomberg New Energy Finance, 2015], the levelised cost in the analysis does not include network costs. For instance in Part 2, the distribution of hydrogen is not included in the considered system. However, it is not of great importance since it is assumed that either the existing hydrogen or natural gas grid will be used. Another limitation is related to the input data. These are deterministic values resulting in one single output. This is the case for the costs, the RES load factors and the market prices. For instance, the additional cost when operating offshore (assumed 100%) has a considerable impact on the cost-effectiveness of the OFF scenario but the validity can be questioned since this forecast towards 2050 entails substantial uncertainty. The deterministic approach is in contrast with stochastic values or ranges where uncertainty is incorporated (e.g. Monte Carlo simulation). However, in this study uncertainty is dealt with through sensitivity analyses where deemed relevant.

8.2 Theory

Theories support the approach taken in the analysis. In this section, the impact of the used theories on the results is discussed. First the concept of smart energy systems is dealt with followed by the multi-level perspective (MLP) and transmission expansion planning (TEP).

Smart energy systems

First of all, the concept of power-to-gas clearly implies interaction between different grids and sectors related to energy. There is interaction between the electric grid and the gas grid (either natural gas or hydrogen) due the energy conversion of electricity into hydrogen. Next, many sectors are integrated thanks to this conversion: industry, transport and heating. The thermal grid is not included but future opportunities, such as power-to-heat, are considered in in view of a future increase in district heating systems in Belgium. In view of future deployment of district heating, it should also be remembered that electrolysis produces heat as well. With 10% of the input electricity being released as waste heat (predicted by Danish Energy Agency [2018a]), the overall ON P2P scenario produces 12.7 TWh of heat, representing about 10% of the Belgian heat demand. Thus, tremendous amounts of heat are wasted which could in fact be valorised and could improve the economic feasibility.

Furthermore, the theory of Smart energy systems has led to the integrated approach, by combining long-term storage and fulfilling the green hydrogen demand. In this way, balancing of the electricity grid is not longer separated and a wider perspective is applied. Moreover, the results confirm the statement by [Lund, 2014] that Smart energy systems lead to more cost-effective solutions. As concluded in the integrated approach, the system cost when combining both purposes appears indeed to be lower than in the case of purely separate systems.

Multi-level perspective

Generally, the influence of MLP is found in the fact that both incumbent technologies and competing niche technologies are considered at every step.

When estimating the hydrogen demand in 2050, hydrogen is not assumed to conquer the entire market in the whole future. Shares for the use of green hydrogen are estimated while the rest of market can be filled by other upcoming green technologies. For instance with regards to transport, specifications were compared to the ones of BEVs so as to determine vehicle types suitable to hydrogen. However, the market shares of other technologies are not concretely specified in the various demand sectors and consequently, the demand is not investigated at the system level. As the demand is the starting point of the energy system in Part 2, it also has an impact on the set capacities of the electrolyser and the wind farm. Furthermore, MLP initiates the focus on the CO_2 price in Part 2. Thanks to a strong landscape which includes movements of civil society, climate change and many more, the regime is pushed towards truly applying 'the polluter pays' principle.

In Part 3, the energy system is first based on the regime after which additional solutions were searched for. Both incumbent alternatives such as interconnection capacity and PHES, and niche technologies such as redox-flow batteries were taken into consideration. However, these solutions are analysed qualitatively and are not included in the hourly model. For instance, no integrated model with the other grids in the EU is performed. The consequence is a local perspective excluding imports and exports. Including them would have a considerable impact on the need of long-term storage as well as on the capacities needed in the related storage system. The same can be said about demand-side management.

Transmission expansion planning

TEP has led to the creation of the OFF scenario. In this way, it was investigated if there is an alternative to the usual electric cables to connect wind farms which is evenly or more cost-effective. It was also taken into account that there would be need for capacity expansion of the current main grid in case of the ON scenario.

8.3 Offshore electrolysis

Part 2 of the analysis shows that offshore electrolysis would be more expensive and less cost-effective than onshore electrolysis. In contrast with the results in my report, other countries, such as the Netherlands, seem to continue investigating this path. For instance, the Netherlands has launched the North Sea Energy Program where an offshore pilot plant is planned [Peters, 2018]. These countries are steered by the expected massive costs related to the gradual decommissioning of offshore gas infrastructure, including platforms and pipelines. Two studies have been published, by Jepma [2017] and World Energy Council Netherlands [2017], where the *decommissioning bonus* contributed in a better economic feasibility. It was mentioned before that Belgium will face a similar situation with its gas pipelines. However, Belgium does not own gas platforms of which the decommissioning is much more expensive and does not face this pressure.

Opportunities for hydrogen production are also found in the Dogger Bank project. The TSOs of The Netherlands, Germany and Denmark, together with Gasunie (Dutch gas grid operator) and the port of Rotterdam have joined forces to build an energy island with 30 GW of offshore wind capacity. Besides being an inter-connector between the North Sea countries, the island would also allow surplus wind power to be converted into hydrogen. [World Energy Council Netherlands, 2017]

8.4 Offshore wind power

In Part 2 and 3 of the analysis, it was concluded that the electricity cost has an extremely high impact on the economic case of both hydrogen production and hydrogen storage (P2P). The LCOH of both scenarios in Part 2 gets much more competitive with a lower electricity cost than the projected LCOE of offshore wind by 2050 (64 €/MWh). This might rise the question if other RES are more appropriate, with *PV* and *onshore wind* as currently the most developed technologies. This only applies to the ON scenarios given that the OFF scenario does not allow other RES than offshore wind power in its set-up.

Onshore wind is less expensive than offshore wind. The expected LCOE for 2050 is about 50 €/MW, being lower than offshore wind's LCOE. However, higher offshore cost reductions are expected.

PV could be used for the electricity input as well and has various advantages. First, PV has by far experienced the most cost reductions. From 2010 to 2017, the price of PV modules in Europe decreased by 83% and this trend is likely to continue [IRENA, 2018]. For a 300 MW solar farm in Saudi-Arabia, the lowest bid was only 1.79 $ct/kWh (or 15.2

€/MWh) [van Wijk, 2018]. With such a LCOE, the LCOH in the ON scenario would be about 2€/kg. Compared to the market price of 2.88 €/kg with SMR, the economic feasibility would increase substantially. Another advantage over wind power is the fact that PV operates in DC. This means no conversion from AC to DC is required, as is the case in the energy systems in both scenarios of Part 2 in the analysis. Thus, less energy losses occur and the cost related to the conversion is also avoided. Auxiliary equipment (cables, invertors etc.) is mainly available in AC nowadays, which is a possible barrier.

However, these other RES also have some drawbacks and the focus on offshore wind power was chosen because of several reasons. Furthermore, it should be looked at from the Belgian perspective.

Despite the narratives about extremely cheap electricity, one needs to keep in mind that the same climate conditions as in Saudi-Arabia cannot be found in Belgium. On average, the radiation is more than twice as high as in Belgium on an annual basis (2,300 vs 1,100 kWh/m2) [van Wijk, 2018]. The seasonal variations also have a big impact since during winter, the PV yield is very low in Belgium, not resulting in excesses or even in enough power to feed to the electrolyser. In contrast with wind power, of which the seasonal effect is weaker and excesses can occur during the whole year. The lower utilisation of the PV capacity, compared to regions with high radiations, also means the LCOE is considerably higher in Belgium. Consequently, it is uncertain if further cost reductions will be high enough to have such low LCOEs of PV in Belgium.

Next to the lower radiation, other specific characteristics of Belgium have to be taken into account. Belgium is a very dense country, facing a considerable pressure on space already. Especially with regards to PV, the land-use change caused by solar farms should be kept in mind as the few open space would be sacrificed. This also counts for onshore wind farms. So, PV and onshore wind can rather be seen as distributed generation. In case of distributed generation, a direct connection is not feasible and the condition of 100% RES could not be guaranteed. However, Belgium has the biggest solar farm of the Benelux, built on a previously industrial site with polluting waste [Aertssen et al., 2018]. One other big solar farm (100 MW) is under development, but in general, one can state that Belgium rather focuses on PV installations on rooftops. However, future developments in floating solar farms in the North Sea might change this [Interesting Engineering, 2018].

Note that *hybrid* systems could be a solution as well. It could be a combination of smaller capacities of PV and wind instead of narrowing down to one kind of RES. Since their energy yield is dependent on different weather conditions (solar radiation versus wind velocity), they can complement each other at some moments, resulting in a higher utilisation factor of the electrolyser, compared to single systems where adding extra capacity only leads to oversized plants, while having minimal impact on the utilisation. Aertssen et al. [2018] found that adding 2MW onshore wind power to a 15 MW solar farm increases the utilisation factor of a 1 MW electrolyser by 20%, from 41.5% to 65.5%, while adding more PV does almost not have an impact. The flexibility in the ON scenario concerning the electricity input can be considered as an additional advantage over the OFF scenario.

Another option for increasing the utilisation factor would be additional storage of electricity between the RES and the electrolyser. This option was not included in the analysis but it is relevant to consider with respect to optimising the utilisation factor and minimising the LCOH. This could be in the form of battery storage where both high cost reductions and technical developments are expected [IMEC, 2018]. Taking into account the hydrogen storage, this would mean a *hybridisation* of storage as well. This hybridisation strategies (of both RES and storage) could avoid oversizing of power capacities.

8.5 Impact on Belgium's energy system

It appears from the analysis that massive amounts of offshore wind power are needed in order to fulfill the forecasted demand by 2050. In general, one can state that electrolysis is an energy-intensive process. 84 TWh of electricity is needed to supply 56 TWh of hydrogen. This consumption is comparable to the forecasted yearly electricity consumption by 2040, being 94 TWh and 17% of the total final energy demand of the country in 2017. Given the scale of the system, it is relevant to also consider the mutual impact on the entire Belgian energy system and even broader.

The required 25 GW offshore wind farm can be considered extremely big in current circumstances. It is 12 times the capacity that will have been installed by 2020 in the Belgian North Sea. However, it was stated before that it is technically feasible when territorial waters of neighbouring countries are leased, but here it should also be noted that it depends on these countries' own national plans.

When looking at it from a European perspective, 16 GW of offshore wind capacity is currently installed of which 11 GW in the North Sea. The average size of a wind farm constructed in 2017 was 493 MW but a quickly increasing trend can be noticed (cf. Dogger Bank project). [WindEurope, 2018] Furthermore, technical and economic improvements as well as politic goals might facilitate the large-scale deployment of offshore wind.

Nevertheless, one should keep in mind that the green hydrogen demand might be overestimated as it was already said to be rather ambitious. One option could be to focus on particular sectors while not trying to cover the entire demand. The full potential of green hydrogen does not have to be achieved but the sectors where other less electricity-intensive alternatives are available should rather be omitted.

In light of the foregoing, one could also look at it from a global perspective by counting on imports from neighbouring countries or even more faraway countries with more suitable circumstances (climate and geographical) to RES and consequently very cheap RE as for instance Saudi Arabia. The production and consumption do not necessarily need to be at the same places, and consequently, hydrogen could be produced where its the cheapest and be distributed to where the need is located. An example for that is Japan which plans to import hydrogen from hydrogen production plants in Australia (as mentioned in Chapter 3).

When considering both fulfilling the green hydrogen demand and the 2050 RES scenario, each plan requires a lot of additional offshore wind capacity. One should be aware that those plans will be competing for the same space and resources.

Both in Part 2 and 3 of the analysis, the electrolysers are characterised by rather low utilisation factors, even if both purposes are coupled. It was found that both increasing the utilisation and access to market prices considerably lowers the LCOH. In case the additional 25 GW offshore wind farms appears not be feasible (because of foregoing reasons), one could aim for lowering the electrolyser capacity while consuming electricity from the grid, even though the origin of electricity is uncertain. However, the impact on the electricity system would be enormous. It would almost double the electricity demand. The residual load would be enormous in the 2050 scenarios and even more solutions such as storage or additional thermal capacity would be needed. One should at any time avoid that fossil-fueled thermal capacity is added so as to supply the sufficient electricity for producing hydrogen. Electrolysers for meeting the hydrogen demand could in fact also absorb electricity excesses and thereby contribute in balancing the system. Nevertheless, this would not contribute in decreasing the residual load while taking the potential away for hydrogen storage (and other storage solutions) that additionally contributes in filling gaps of the supply.

8.6 Regulatory framework

All results in this study are based on a strong base of support towards green hydrogen and alternative fuels in general. Likewise, the forecasted green hydrogen demand assumes such support and the eventual demand by 2050 is highly dependent on it. The European policy as well as the Belgian and regional policy should enable niche technologies to achieve penetration at a high level. This requires an elimination of the perceived regulatory barriers and a clear regulatory framework with regard to green hydrogen. Consequently, it is relevant to have an overview of the regulatory aspect by starting from the current situation.

Among various stakeholders of the hydrogen economy, there is a consensus about the lack of such a regulatory framework [Brahy, 2018]. An appropriate regulatory framework consists of two parts: positive legislation and changing negative legislation. Positive legislation refers to stimulating and facilitating measures. As discussed in Chapter 3, niche technologies need to be developed in *protected arenas* where for instance, subsidies are one way of doing this. On the other hand, there can also be negative legislation, i.e. barriers in the regulatory framework in the current regime which need to be removed. Those barriers are not necessarily meant for excluding certain niche technologies but are often a result from previous legislation which is not yet updated.

Support schemes and taxes do not have an impact on the socio-economic case, but they are nevertheless discussed given the boost to green hydrogen they can create.

Table 8.1 gives an overview of all the regulatory elements in which green hydrogen could play a role. Note that this is not necessarily the case at the moment. It is assessed how these elements are barriers or possible catalysts to the green hydrogen's deployment.

With regards to the *RED* for transport, an important role is given to advanced bio-fuels. Towards 2020, those bio-fuels enjoy double counting, discouraging other solutions. By 2030, the target is decreasing to 6.8% (because of the decrease in first generation bio-fuels) of which 5.3% is planned to come from bio-fuels. Green hydrogen could be part of the residual 1.5%. However, green hydrogen is quoted based on the electricity input. So, this

Regulatory driver	Relevant elements	Impact			
		IND	TRAN	HEAT	P2P
Renewable Energy Directive (RED)	20%/27% RE by 2020/2030. 10%/6.8% RE in transport		x	x	x
Fuel Quality Directive (FQD)	6% decrease in GHG intensity of road fuels in 2010-2020	x	x		
Alternative Fuel Infrastructure Directive	Minimum requirements; Encouraging member states to make national policy framework		x		
Air quality Directive	Promotion of low emission zones (LEZ)		x		
Emission Standards Passenger Cars	Promoting energy-efficient transport; Maximum CO_2/km allowed for new vehicles		x		
EU ETS	GHG emission trading for energy-intensive installations	x			
Green certificates (Belgium)	Every region has a certificate trading system to support RE. Number of certificates per MWh varies among technologies.	x	x	x	x
Zero-emission vehicles (Belgium)	Grants (only in Flanders) and reduced taxes for BEVs and FCEVs		x		

Table 8.1: Overview of regulatory drivers applying to hydrogen

is either the share of RES in the national electricity mix or, it can be counted as 100% renewable if the electricity is obtained from a direct connection to the source of RE and this source cannot be connected to the grid. This is is only true for the OFF scenario. In the ON scenario, the hydrogen used in transport would not count as 100% RE even though the electricity is directly coming from a wind farm. The excess electricity is injected into the grid so the wind farm is not off-grid.

The *FQD* considers the GHG emissions during the whole life-cycle of the fuels (so called well-to-wheel emissions). Green hydrogen could play a role in this, either in FCEVs or refining activities, but however, the target is too weak and not encouraging the fuel industry to change. Any FQD development beyond 2020 is unknown.

More and more *LEZs* arise across Europe and also in Belgium. Belgium already counts two LEZs (Antwerp and Brussels) and other cities have announced future plans [ECC Belgium, 2018]. LEZs mainly address the local air pollution problem in cities. Therefore, BEVs and FCEVs are particularly favoured as being zero-emission cars. Note that an LEZ focuses on the tank-to-wheel aspect (impact while driving) rather than the well-to-wheel aspect.

This implies that green hydrogen is not favoured over grey hydrogen.

Emission standards for the sale of new passenger cars are at the moment still allowing efficient diesel or petrol cars. Thus, the automotive industry is still triggered to make conventional ICE vehicles more efficient instead of totally switching to zero-emission vehicles. However, beyond 2020, the allowed CO_2 emissions will drop steadily so as to phase out conventional ICE vehicles. This will open up big windows of opportunity to emerging niches.

The *ETS* has been discussed before as being essential in the penetration of green hydrogen in the industry sector. As the carbon price is currently low, the impact when producing grey hydrogen by SMR is also low and consequently it is hard to compete with. However, it was also mentioned that the carbon price in the ETS is expected to rise from 6 €/ton CO_2 to 88 €/ton CO_2 by 2050.

Next to all regulatory drivers in Table 8.1, the European Commission will present new gas regulations in 2019/2020 that will contemplate clean gases as well.

Apart from the European level, the Belgian and regional regulatory framework also have a big impact on the penetration of green hydrogen into the Belgian energy system.

First, *green certificates* are currently awarded to wind farm owners per MWh hour of electricity injected into the grid. This means that, if the the wind energy is used for conversion into hydrogen instead of for using it in the main electricity grid, no green certificates would be awarded. Nevertheless, the existence of such a certificate system is uncertain towards 2050 as offshore wind power will get cheaper taking away the need for subsidies.

An additional regulatory barrier in Belgium, is the *legal status* and the lack of it with respect to the production and storage of hydrogen. The existing framework on hydrogen is only focused on industrial applications. No framework exists for hydrogen refuelling stations, P2P installations and the injection of hydrogen into the gas grid. They are considered as normal energy consumers and pay the corresponding fees and taxes. Hydrogen storage facilities belong to the chemical industry, consequently resulting in heavy procedures.

By giving *grants* up to 4,000 € when purchasing zero-emission cars or small vans, Flanders clearly expresses the direction it wants to go to. The grant does not compensate the gap with conventional ICE vehicles but it surely gives an incentive to car owners. Next to legislative aspects, it is relevant to discuss the general support in Flanders from other stakeholders than the government as well. Supported by the Flemish Agency for Innovation and Entrepreneurship (VLAIO), the *Power to Gas cluster* was created which connects companies (currently 28 members), operating in different fields of the power-to-gas market. Hence, they can reinforce each other and join their efforts in demonstration projects. In this way, the Flemish industry wants to position itself in the European power-to-gas market, while also informing policy makers about the perceived regulatory barriers. In the Brussels-Capital Region and in Wallonia, there is generally less support for a hydrogen economy.

A missing link in all addressed regulatory drivers as the FQD, RED or ETS, is how it can be proved that the hydrogen is obtained from 100% RE. It is essential to emphasize this difference and to look at the entire life-cycle since hydrogen produced through electrolysis does not necessarily mean that it is green or low-carbon. When the input electricity is 100% coming from natural gas, the emissions are twice as high than when produced through SMR (also 100% natural gas) [Castro et al., 2015]. The analysis has shown electrolysis is a very energy consuming process so it has to be guaranteed that the electricity comes from renewables.

Therefore, a certification system is needed for green hydrogen. A Guarantee of Origin (GoO) to proof the renewable origin is proposed as the solution. A similar system already exists for electricity and biogas (in some EU member states). The EU project *CertifHy* is currently developing such a certification mechanism. When green hydrogen becomes a means to comply with regulations, it will become a true option e.g. by refiners.

8.7 Further work

This report has presented a broad view on the role of green hydrogen in Belgium. In case of further implementation, there are supplementary aspects which are important to look at but which are out of the scope of this report.

As pointed out before, the distribution side is excluded throughout the analysis. If one aims to assess the whole system cost, this element should be added. Thereby, an additional full electric scenario could be created where hydrogen is replaced by electricity where possible, both in the end-uses of hydrogen as in storage. In doing so, the system cost of a system with and without hydrogen could be compared which could strengthen the validity of this report.

By covering the whole supply chain, the by-product hydrogen produced in the chemical industry could be incorporated as well. This was excluded in the analysis and might fulfill part of the hydrogen demand when not directly used on-site for electricity production and in case of acceptable purity. Chlor Alkali and propylene plants are already injecting or plan to inject in the Air Liquide hydrogen grid.

Furthermore, field research should be performed. As the reports proposes locations for the offshore wind farm, the electrolyser and the storage system, it is relevant to examine the suitability of these locations in a more thorough manner. In view of distribution and storage facilities, further interaction with the operators of the hydrogen and natural gas grid, Air Liquide and Fluxys respectively, could provide new opportunities and advanced knowledge.

Lastly, European integration of the energy system would be relevant in view of available import/export capacities. This requires advanced knowledge of the electricity systems in the connected countries. Besides, given the fact that electricity prices are determining in the economic feasibility of hydrogen storage, new hourly electricity prices according to the 2050 RES system could be calculated.

9 Conclusion

This thesis report investigates the *role of green hydrogen in Belgium's energy system by 2050.* Electrolysis consuming electricity from 100% RES converts water into green hydrogen as opposed to grey hydrogen produced through SMR with natural gas. As such, it appears this niche technology offers opportunities in the decarbonisation of society as well as in the integration of intermittent renewables where offshore wind connections and grid-balancing become more difficult. Three specific sub-questions are answered with the goal of assessing the role of green hydrogen from a socio-economic viewpoint:

1. *What is the future demand for green hydrogen in Belgium?*

An advantage of hydrogen is that it can be used in a broad range of applications. The hydrogen demand was divided into three sectors: *industry*, *transport* and *heating*. Forecasts towards 2050 resulted in a total yearly green hydrogen demand of 1659 kton or 55 TWh (the current final energy demand is 49O TWh). Transport will be responsible for the biggest share, at 54%, followed by industry (33%) and heating (13%). Accordingly, if hydrogen in transport does not break through, merely half of the assessed demand has to be met.

2. *Under what circumstances can offshore wind power be the source of an efficient and cost-effective hydrogen production?*

An energy system is assessed composed of electrolysis and a wind farm, driving the electrolysis with its intermittent power. Two scenarios were created differing in the electrolyser's location. In the ON scenario, the electricity is first transported ashore from the wind farm, followed by *onshore* electrolysis. In the OFF scenario, the electrolysis is performed *offshore* and hydrogen transport replaces the electric connection. A socio-economic analysis was performed so as to compare the cost-effectiveness of the scenarios.

First, the capacities of the electrolyser and the wind farm were dimensioned through minimising the levelised cost of hydrogen while meeting the hydrogen demand that resulted from the first part. A 24.5 GW wind farm and a 22 GW electrolyser were concluded to be the cost-optimal solution for both scenarios, with a corresponding utilisation rate of 43%.

With an LCOH of 4.5 €/kg, the ON scenario is more cost-effective than the OFF scenarios, of which the LCOH is 5.2 €/kg. The additional offshore costs as a result of difficult access, extra equipment and protection against the sea climate, is mainly responsible for the difference. The avoided HVDC infrastructure is not sufficient to offset these costs. However, the OPEX represents 80% and 76% of the LCOH for the ON and OFF scenario respectively, where the electricity cost is clearly the dominant element. Accordingly, the future development of the electricity production cost from offshore wind has a high impact on the LCOH of both scenarios.

When put in a market context, neither LCOHs are competitive to the predicted price of 2.88 €/kg for grey hydrogen. However, other factors such as the natural gas price or the carbon price, might push the price higher (or lower) and furthermore, within the transport and heating sector, it competes with other alternatives such as diesel cars for transport. GoO certification to prove the renewable origin could also increase green hydrogen's market value and boost the green hydrogen demand.

> *3. What is the future need for long-term storage to support Belgium's electricity system and under what circumstances will hydrogen be a feasible storage solution?*

The grid-balancing needs in terms of *residual load* and *excess electricity* were assessed for a 2050 RES scenario. A yearly residual load of 13 TWh and yearly excesses of 27 TWh were found which are 14% and 29% of the forecasted yearly electricity demand, respectively. Given that such imbalances may last for multiple days, long-term storage is a suitable solution where *hydrogen storage* (P2P) was selected. Using forecasted electricity market prices, the levelised cost of reinjecting 1 MWh was 46.6 €/MWh, which can be considered as the amount to be covered by the reinjecting benefit. Given that hours of residual load are typically associated with electricity prices in the upper range, a positive economic case is expected. The hydrogen production in the P2P system is characterised by a negative LCOH, due to many hours with negative prices at moments of excess. Hence, it can be generally concluded that a P2P system is only economically feasible with very low electricity costs and high electricity benefits from injection.

Furthermore, an integrated approach is applied by using the electrolyser in the ON scenario for grid-balancing purposes as well. The yearly cost of the integrated system appear to be lower than when both purposes are approached separately, but the difference is rather small. Further integration with heating, e.g. in a district heating system, would also improve the economic feasibility as large amounts of waste heat generated through electrolysis could be valorised. However, this potential is limited in Belgium given the extremely low deployment of district heating.

One can conclude that green hydrogen definitely will have a key role in a future renewable energy system for Belgium. Belgium disposes of a large potential for green hydrogen in current fossil fuel-based applications. Nevertheless, access to cheap renewable electricity will be crucial in a steady and competitive supply and it is uncertain if Belgium can satisfy this requirement. Other emerging green niches may also account for part of the potential. In any case, onshore electrolysis should be chosen over offshore electrolysis, preferably integrated with a hydrogen storage system. Hydrogen storage is a feasible option in unbalanced systems with a high degree of variability in the electricity prices, and is, just like the green hydrogen demand, of great importance in decarbonising society in a viable way.

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Interviews A

A.1 Isabel François - WaterstofNet

As project manager at WaterstofNet, Isabel François with a current study of the Flemish Energy Agency about the potential of green hydrogen in Flanders in the framework of the H2Vlaanderen project. This study is one the main sources in the estimation of the future hydrogen demand in this report. Both data and methodology have been used where suitable. As the available publication does not include the underlying data but rather aggregated results, additional questions could be asked during the interview. François provided useful sources and also explained the reasoning behind choices.

A.2 Filip Smeets & Wouter Schuyter - Hydrogenics Europe

Hydrogenics is the global leader in electrolysis and fuel cell technologies and participates in multiple demonstration projects. Both technical as economic data were provided with a focus on predictions towards 2050.

Opening

Filip Smeets states that there is currently a tipping point of hydrogen being reached in the EU at the politic level.

- Model of Greek professor: Hydrogen is necessary in order to achieve deep decarbonization (95%). A strong decrease in CO2 emissions is expected due to sector coupling.
- Directorate-general of transport (DG Move)
- Contracted study about the role of hydrogen in the EU

Feasibility of GW-scale in the future

An enormous breakthrough has been realised in the last years concerning the new PEM technology. Currently, a 3MW electrolyser takes 1500 m^2. a 25MW electrolyser would have a footprint of 20 by 50 meters (plug-and-play), but Hydrogenics expects that same footprint could be sufficient for the double capacity (50MW). In contrast, Alkali electrolysers would need football fields. A typical refinery plant would need about 300 MW electrolysis capacity, that will be easily doable with Hydrogenics' technology. This capacity would also be sufficient at bottle necks in the electricity grid or where the onshore of offshore wind electricity cannot sufficiently be drained. The first module of 5MW is going to be built and shipped to Norway. There are also 2 other projects in the pipeline, one of 20MW and one of 25MW. The 20MW project would take place in Germany where hydrogen would be blended with natural gas. The hydrogen is not separated as this technology is not on point yet. It does not work for percentages below 5% where it is actually needed. However, as things change rapidly, it will probably be possible in the future.

Investments cost

Hydrogenics expects that one can go towards 300-350 euro/kW (system cost). In 2012, there was the high-level idea to reach 600-700 €/kW and Smeets thought it was impossible. With their small Alkali projects, they had 1000-1500-2000 €/kW depending on the unit size. However, they are already at that level now with the PEM technology. Of course, the bigger the scale, the easier it is to do things in a cheaper way, but however, the biggest initial cost reduction will come from the volumes. Currently, Hydrogenics builds about 15-20 MW per year and it is the biggest producer in the world. And now, one project is already going to be 20-25MW in 1-2 years. At state level, 10-15 GW in the next 10-20 years seems reasonable. → Example of Rotterdam: 3 GW of electrolysis needed if the Netherlands wants to achieve the goal of the Paris Agreement to reduce the CO2 emissions by 85% by 2050. This is 100 times more than what Hydrogenics produces today and what supplier deliver to them. It is obvious that with higher volumes, one will go quickly through the cost curve, and that the costs will be reduced automatically, even without technological innovation. With this technological innovation, even more has to follow. Also, electrolysis will come later than fuel cells concerning market volume growth. As both technologies use similar components, electrolysis can 'piggyback' on the developments in fuel cell technology. Prices (commercial) now: 2.5MW : 3 M€ 10MW : 9 M€ 5MW : 4.5-5 M€ 20MW : 18 M€ (or lower)

Lifetime

Smeets thinks it is similar to any other technology. The biggest part of the electrolysis plant is, expect for the cell stack, ordinary existing technology: transformers, rectifiers, pumps etc. The only new technology is the cell stack. The cell stack is very robust as it does not have any moving parts, the only thing that moves is the water and the output gas. You work with pure water so there is no contamination possible. The only thing that wears out is the membrane electrode assembly (MEA). De catalyst that is at two side of the membrane has a decreasing performance. Nevertheless, you can just disassemble the cell stack, replace the membranes and reassemble (circular economy: cradle-to-cradle). 50% of the capex is represented by the cell stack, 30% of the cell stack cost is represented by the membrane. So, 15% of the capex has to be replaced after the membrane's lifetime. There are still improvements expected in the lifetime of the MEA as more supplier will arise when the market gets bigger (now only three). Smeets expects a tripling of the current lifetime which is 40 000 hours, so 120 000 hours by 2050. Hydrogenics also sees a potential in the recycling of those MEAs.

Efficiency

The target for the 20-25MW units is 4.5 kWh/Nm^3 (50 kWh/kg). That is expected to be feasible given what they currently have in the pipeline, without any technological innovation needed. Next, we should hope that there will once breakthroughs concerning the membrane and catalyst technology. The theoretical potential is 380 or 400 kWh/kg (38 or 40?) so it will never be extreme. Losses occur because of the conversion of electricity

(AC-DC). It is a big cost and loss component which can improve but it will always remain. Smeets also points out the importance of the electricity price. Currently, a lot of taxes and levies are imposed next to the commodity price worsening the business case.

Flexibility of operation

It is instant response. You can compare it with a car where you can accelerate and brake.

Offshore electrolysis

Hydrogenics does not have specific experience with that. You need to take into account that the technology is specifically equipped and is resistant to the maritime climate. Otherwise the lifetime of 20 years will never be reached. There are technologies that deal with this (see offshore wind turbines) so that should not be a problem, but it comes with an extra cost. When Hydrogenics gives a special treatment to plants at the coastline, the cost increase is never higher than 10%. However, Smeets thinks that in general the capex will rise enormously in case of offshore, because of operating in the middle of sea (installation etc.). Another challenge and extra cost is the fact that demineralized water as input for electrolysis, so the salt sea needs a treatment.

A.3 Rene Peters - TNO

As Business Director of North Sea Energy, Rene Peters is in the lead of a project in the Netherlands where they look at how they could use the existing gas infrastructure (pipelines + platforms) in the North Sea in the offshore energy system, so by converting electricity from wind farms into hydrogen and by transporting this hydrogen via the existing gas pipelines. As he is an expert in gas technology, the focus of the interview is on hydrogen transport infrastructure.

Costs of retrofitting gas pipelines for hydrogen use

It depends on the concentration of hydrogen, lower concentrations or 100% (aim in the future). It also depends on the pressure. One issue is the fact that hydrogen is a very small molecule and easily leaks through valves and flanges. Another issue is hydrogen cracking where the pipelines degrade, which mainly occurs when there are pressure variations. It is expected that this danger decreases when the pressure is lower, such as 40 bar. This also depends on the material, where a special coating could solve this issue but a high cost. The risk for hydrogen cracking and leakage seems to be much lower for offshore pipelines as they are welded from steel, (according to several studies). In comparison, for flanged pipes, compressors and valves, considerable adjustments needs to be done to mitigate the risk of leakage (Concerning flanges, such an adjustment could be the placement of extra seals which can be relatively cheap and easy). This is usually the case for distribution grids, which may also be constructed from other materials as PVC, plastics, polyethylene... The combination of high pressure and high temperatures can also induce hydrogen cracking (and embrittlement) but this is also not an issue in the North Sea. What also matters is the purity of hydrogen: is there still oxygen, water present etc.?

In the Netherlands, Gasunie (Dutch gas TSO) is currently doing a project where the use of the onshore transmission grid for hydrogen transport is tested. Only the compressors, valves, and flanges at the ends of the pipe are adjusted.

Peters sees it as a big advantage that in this way costly electric lines can be avoided, where this money can be invested in an electrolyzer instead.

Cost of offshore electrolysis

In general, everything that is place offshore is more expensive because of extra protection against the climate conditions etc. As part of the project, they are planning a pilot offshore electrolysis plant. They want to investigate if the plant can be managed remotely where everything is monitored onshore which decreases the costs. Also they want to test how the electrolyzer reacts to the intermittent input of electricity from a wind farm. Normally, costs are two to three times higher offshore than onshore. Looking at installation, maintenance, safety, factor 2 is easily exceeded. On the other hand, one can notice a trend of unmanned offshore activities where cost reductions are aimed for so in the future it may be closer to two than three times. This factor relates to the life-cycle cost. The impact on capex might not be that bat but mainly the installation and operational cost makes it more expensive.

Moreover, the water has to be desalinated implying an extra cost. On the other hand, the transport of hydrogen is much cheaper than transporting electricity, even with a factor higher than 10. Transport via cables has much higher energy losses and has higher capex and opex than molecule transport. However, you need to produce the hydrogen first which is expensive. In the future though, electrolysis will get less costly and wind farms will further from the coast.

Pilot plants will have to be subsidized towards 2030 but afterwards, when they get more competitive, they can be deployed on a big scale.

Extraction of hydrogen from a mix with natural gas

In fact, it is not hard to separate hydrogen as it is a very light and small molecule but it comes with an cost. Peters states that it is only useful for high volumes.

A.4 Lars Udby - Hydrogen Valley

Hydrogen Valley is a partner in the EU HyBalance project, a project which demonstrates the use of hydrogen in energy systems with a pilot plant at Hydrogen Valley's site (Denmark). As Chief Project officer, Lars Udby has advanced knowledge related to this project.

What is the project?

The demonstration plant includes a 1 MW PEM electrolyser. The operation is controlled based on two parameters: the hydrogen demand and grid-balancing services. The hydrogen demand comes from local industry and transport. Due to limited storage capacity, one does not produce if there is no demand. With regards to grid-balancing, the cost of electricity is minimised and electricity is bought at two markets: spot market and frequency control reserves (FCR or primary reserves). FCR seemed to improve the business case significantly (result from economic analysis by Neas). Only up-regulation is planned as the the plant does not include re-electrification (negative business case). Minimising the electricity cost is part of the overall aim to minimise the production cost of hydrogen.

A.4.1 Why has the project started?

The projected started with Air Liquide that was interested in green hydrogen production and because of the expected positive business case when grid-balancing is included.

A.4.2 Long-term perspective

The demand for hydrogen is fairly low in Denmark, and L. Udby does not expect a significant growth, not even in the transport sector. That is the reason why they are looking at conversion into Methanol for a new 20 MW electrolyser project.

Map offshore scenario B

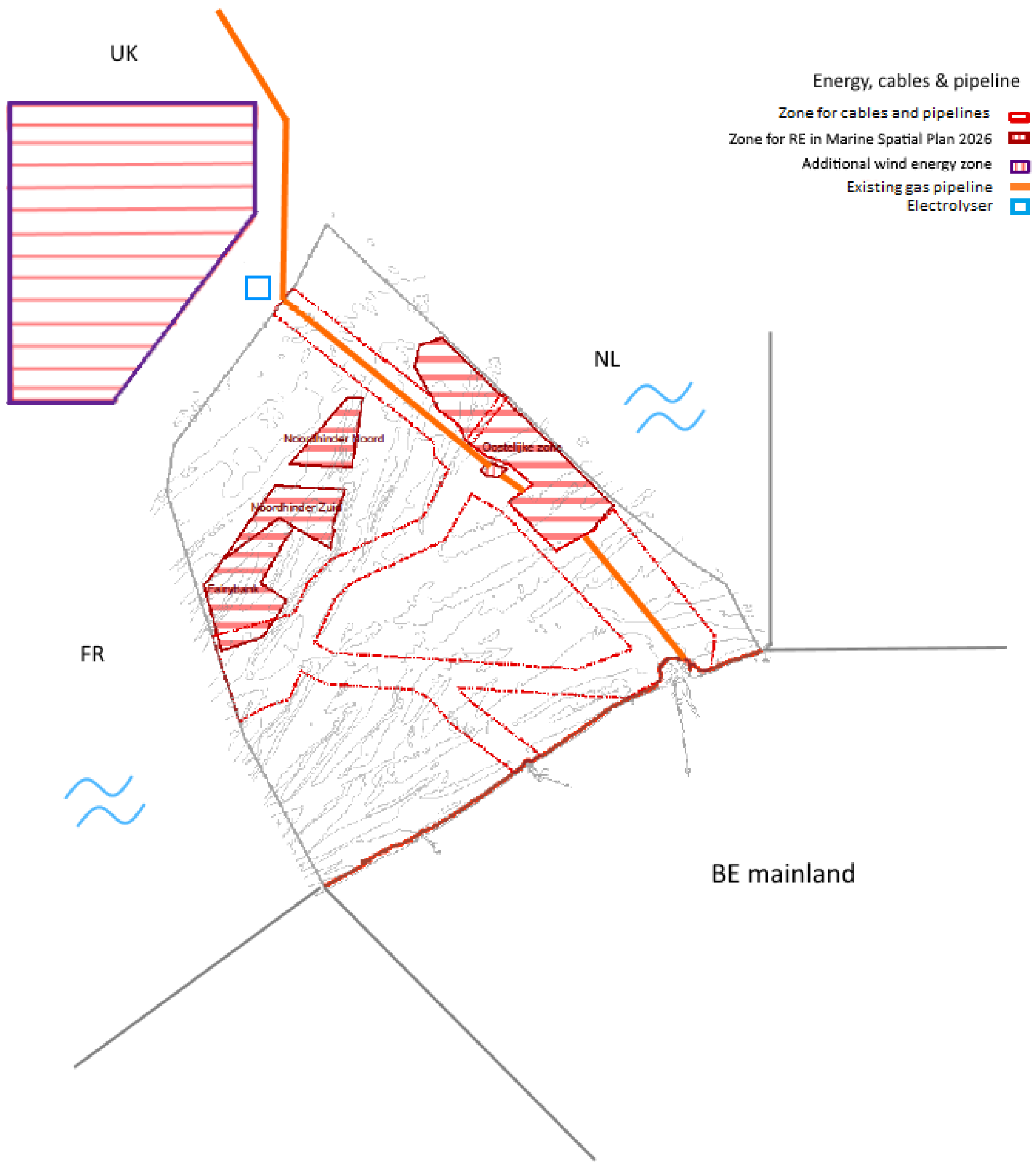

Figure B.1: Map of the set-up in the offshore scenario put in the context of the Marine Spatial Plan for 2026

C Capacity optimization

Offshore wind capacity [MW]

Electrolyser capacity [MW]

LCOH [€/ton]	22000	22500	23000	23500	24000	24500	25000	25500	26000
15000	4,812	4,854	4,897	4,940	4,984	5,028	5,073	5,118	5,164
15500	4,757	4,796	4,836	4,877	4,919	4,961	5,004	5,047	5,091
16000	4,707	4,744	4,782	4,820	4,860	4,900	4,941	4,982	5,023
16500	4,661	4,696	4,731	4,768	4,805	4,843	4,882	4,921	4,961
17000	4,620	4,653	4,686	4,720	4,755	4,791	4,828	4,865	4,903
17500	4,584	4,613	4,644	4,676	4,709	4,743	4,778	4,813	4,849
18000	4,552	4,578	4,607	4,637	4,668	4,699	4,732	4,765	4,800
18500	4,524	4,548	4,573	4,601	4,630	4,659	4,690	4,722	4,754
19000	4,501	4,521	4,544	4,569	4,595	4,623	4,652	4,681	4,712
19500	4,486	4,500	4,519	4,540	4,564	4,590	4,617	4,644	4,673
20000	4,481	4,485	4,498	4,516	4,537	4,560	4,585	4,611	4,637
20500	4,492	4,481	4,485	4,497	4,514	4,534	4,556	4,580	4,605
21000	4,508	4,493	4,482	4,484	4,496	4,512	4,531	4,553	4,575
21500	4,528	4,508	4,493	4,483	4,484	4,495	4,510	4,529	4,549
22000	4,549	4,529	4,509	4,494	4,483	4,484	4,494	4,508	4,526
22500	4,570	4,549	4,529	4,510	4,495	4,484	4,483	4,493	4,507
23000	4,591	4,570	4,549	4,529	4,510	4,495	4,485	4,483	4,492
23500	4,612	4,590	4,569	4,549	4,529	4,511	4,496	4,485	4,483
24000	4,633	4,610	4,589	4,568	4,549	4,530	4,512	4,497	4,486
24500	4,654	4,631	4,609	4,588	4,568	4,549	4,530	4,512	4,497
25000	4,675	4,651	4,629	4,608	4,587	4,567	4,548	4,530	4,513

Figure C.1: Levelised cost for electrolyser and wind capacities SC2