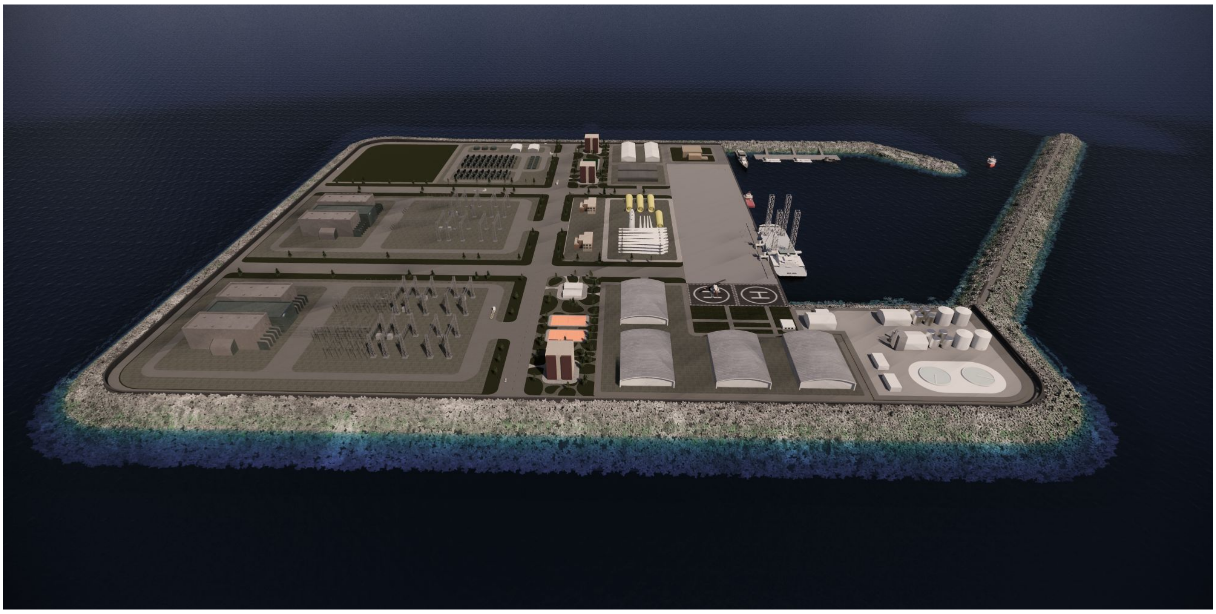
Faculty of Engineering Technology

master thesis

Sustainable Energy Technology



Offshore Service Facilities, source: Royal Haskoning DV

Techno-economic study of a power-to-hydrogen system in offshore wind energy

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Summary

The increased demand for carbon neutral energy provision has led to a rise in installed renewable energy, especially offshore wind capacity is increasing for countries adjacent to the North Sea. An energy hub has been proposed and elaborated by the North Sea Wind Power Hub consortium. This study determines the business case for offshore hydrogen production on an energy hub. The main components taken into account are the island, wind farms, electrolyzer system, electricity submission by cables and gas transport by pipelines. To determine the business case for this entire system, the Wind Hydrogen Simulation (WHS) model is created to size the system and to determine the total costs for each component for installed wind capacities of 12 and 20 GW. One of the operation modes tested is the market optimized mode, loading the electrolyzer if the electricity is cheap and thus the smoothed EPEX spot price is low (see Figure 1). This operation mode is tested for different wind and stack capacities, sizing the systems cable and pipeline capacity. The results are displayed by calculating the levelized cost of energy of the system (LCOE), the net present value (NPV) and the system pay-back period (PBP). Main findings are that the addition of hydrogen conversion increases the LCOE because the investment costs (CAPEX) are higher and due to energy losses in the electrolyzer less energy is delivered to shore. Nevertheless it can improve the NPV and PBP of an offshore wind system. Furthermore, opportunities for reducing the total system costs have been proposed and further research topics are suggested which could possibly enhance the profitability of hydrogen production on an island in the North Sea.

Figure 1: Load power for peak load operation mode (1) (top left), base load operation mode (2) (bottom left), market optimized operation mode (3) (top right) and the relative 4-day smoothed EPEX price (bottom) for a duration of 7 days

Preface

Already two years before I finished high school, I was sure about studying Mechanical Engineering at the University of Twente. Eventhough it took me some effort to pass all courses, I am really thankful for the technical knowledge I gained during the bachelor program. An internship abroad in South Africa during the minor courses has really encouraged me to focus on sustainable energy and I decided to start the master Sustainable Energy Technology. My passion is to make this world a better place for everyone. I am looking forward to put this in practice by being involved in international sustainable energy projects.

I want to thank Witteveen+Bos for the opportunities they provided me during this graduation assignment. At the start I was looking for an assignment related to offshore wind energy and I am glad Witteveen+Bos gave me confidence in elaborating on this topic. In particular I want to thank my daily supervisor Emiel van Druten for his huge enthusiasm and the useful ideas proposed in the beginning and during the internship.

The project was also challenging, because I had to continue working from home after six weeks of internship in Deventer. However, I enjoyed the online meetings and interviews which always gave me a motivation boost. For example, the interview with Neptune Energy related to the PosHYdon project was one of the highlights during my project, since it convinced me that my research is relevant and challenging at the same time.

Last but not least, I want to thank my family and friends. My mom and dad has been my biggest supporters since the start of my studies back in 2013. I also want to thank my girlfriend Willemijn who always encouraged me in times I was struggling to motivate myself while working at home. I am glad to finish this project and I am looking forward to the near future.

Derko Budding
Enschede, August 2020

Nomenclature

CAPEX Capital expenditure

DC Direct current

EPEX European Power Exchange

HHV Higher heating value

HVAC High voltage direct current

HVDC High voltage direct current

IEA International Energy Agency

IRENA International Renewable Energy Agency

LCOE Levelized cost of energy

LHV Lower heating value

LT Life time of the entire system

NIB Northern Innovation Board

NPV Net present value

NSWPH North Sea Wind Power Hub

OPEX Operational expenditure

OWF Offshore wind farm

P2G Power-to-gas

P2H2 Power-to-hydrogen

PBP Pay-back period

PEM Proton exchange membrane

TSO Transmission system operator

UNFCC United Nations Framework Convention on Climate Change

WHS Wind Hydrogen Simulation model

Contents

Chapter 1

Introduction

1.1 Renewable Energy

Since the earth's climate is changing and global warming is observed over the last few decades, the United Nations Framework Convention on Climate Change (UNFCCC) set the goal to limit the increase in earth's temperature to 1.5 °C recognizing that this will minimize the risks and impact of climate change [1]. This UNFCCC framework was established at the climate conference COP21 in 2015, resulting in adapted national policies towards larger share of renewable electricity in their energy mix. Consequently, this has led to a total net installed renewable generation capacity in 2019 of 176 GW to reach a cumulative global renewable installed capacity of 2,537 GW at the end of 2019 (37% increase with respect to 2015) [2]. From this total installed renewable capacity, 90% accounts for solar and wind energy sources and the remaining 10% is a mix of hydropower, biomass based and other conversion technologies. This study will focus on offshore wind energy.

1.2 Offshore Wind Energy

Offshore wind has emerged as one of the most promising technologies in the renewable energy system especially for the North Sea countries. The future wind farm installation rate per year is increasing exponentially. This is required to reach the goals set by the European Union to reach 60 GW of installed capacity in 2030. In recent years, offshore wind farms were installed by the European countries adjacent to the North Sea, such as The Netherlands, United Kingdom, Germany, Denmark and Norway have invested in multiple wind farms in the last few years. This resulted in adding 3.6 GW of new gross capacity in 2019 with a cumulative offshore wind capacity for Europe of 22 GW representing 5,047 grid-connected wind turbines according to the latest annual statistics of WindEurope [3]. For 2050 the European Commission estimates the required offshore wind capacity is in the range of 240 and 450 GW in order to be carbon neutral within Europe [4]. The largest wind turbine has been installed in 2019 at Rotterdam Port, the Haliade-X 12 MW. The developments for this prototype could be leading in the size and capacity of future offshore wind farms in European waters.

Currently, the largest Dutch wind farm is installed and commissioned, the Borssele I & II consisting of 94 Siemens Gamesa 8 MW wind turbines to reach a total installed capacity of 752 MW. The wind farm is connected via a 700 MW HVAC platform by the Dutch transmission system operator TenneT. For further large offshore wind farms, TenneT is developing a new generation 2 GW transformer platform with 525 kV HVDC export connection [5]. The integration of offshore wind energy into the onshore energy system becomes a bottle neck in the period around and after 2030 when the most remaining connection capacity at onshore landing points has been used. In combination with the intermittent behavior of wind energy this means that the risk of wasting energy, also known as energy curtailment. This demands for alternative energy carriers, in order to save the generated wind energy. A viable solution to this problem could be an energy hub. For instance, TenneT first proposed an artificial island in June 2016, which is also known as the Hub&Spoke concept, elaborated in more detail by the North Sea Wind Power Hub consortium [6, 7]. The latter NSWPH study assumed an artificial island of 6 km^2 to host a maximum installed wind farm capacity of 30 GW.

The main added added value for this concept over a platform is the smart distribution of electricity by installing multiple large capacity inter-connector cables to neighbouring countries. These connectors give access to multiple energy markets and hence it provides new opportunities for smart strategies for both grid stability purposes and increased revenue streams. The concept of an energy hub creates opportunities for energy conversion technologies, such as hydrogen production by water electrolysis. Water electrolysis is favourable over other conversion technologies in offshore wind energy since only electricity and (sea)water is required for the process. Obviously, water is abundantly available in a marine environment. The next section will give an introduction to production of hydrogen by water electrolysis.

1.3 Hydrogen Production

Right at the start of the development of the first wind turbine, experiments were done to split water into oxygen and hydrogen fed by electricity from the wind turbine. In 1891 the Danish meteorologist and inventor Poul la Cour installed the first experimental wind turbine in Askov (Denmark) to store wind energy by producing hydrogen energy and oxygen energy through electrolysis [8]. From then on, the potential for hydrogen in combination with wind energy has been further elaborated and conversion technologies have improved over the years.

The expected increase of intermittent energy generation requires balancing of the supply. Energy conversion and storage are able to offer this flexibility, also categorized as power-to-X (P2X). In general, P2X means to convert electricity into an energy carrier, heat, cold, product or raw material. Power-to-gas systems (P2G) such as power-to-hydrogen (P2H2) is a suitable alternative for fossil based energy carriers. Basically, water electrolysis is the process of splitting water molecules into hydrogen and oxygen by applying an electric load. The basic electrolysis reaction is shown in Equation 1.1. The two half reactions which take place at the anode side (A) and the cathode side (C) are given in Equation 1.2. A schematic illustration of the electrolysis process in a proton exchange membrane (PEM) electrolyzer is shown in Figure 1.1. It clearly shows the exchange of protons through the membrane from the anode side to the cathode side. At the cathode side the protons and electrons are re-coupled to produce hydrogen.

$$H_2O + electricity = H_2 + \frac{1}{2}O_2 \tag{1.1}$$

$$\begin{aligned} A &: H_2O \rightarrow \frac{1}{2}O_2 + 2H^+ + 2e^- \\ C &: 2H^+ + 2e^- \rightarrow H_2 \end{aligned} \tag{1.2}$$

Hydrogen production through electrolysis has the potential to benefit the offshore wind business case by offering an additional revenue stream. The potential for conversion of offshore wind energy to hydrogen has been investigated in determining the production of hydrogen in multiple projects and prototypes mainly located in the northern European countries, such as Norway and The Netherlands. Offshore wind is generally acclaimed to be the most suitable energy source to be penetrated for hydrogen production. The first explorers in this field proposed a combination of hydrogen and wind that could lead to an innovative solution for the energy sector [10].

The global demand for hydrogen has grown more than threefold since 1975 to an average global demand for hydrogen of 73.8 million tonnes in 2018 [11]. From this hydrogen demand, 94% is

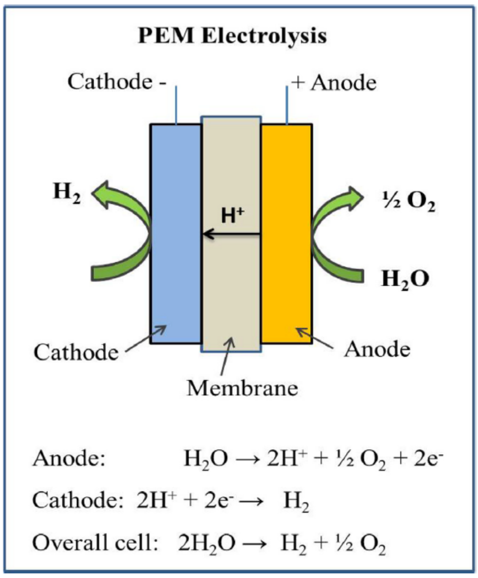

Figure 1.1: Schematic overview of PEM water electrolysis, reprinted from [9]

used in industry for refineries and ammonia production. In both cases, the hydrogen is produced by using steam methane reforming (SMR) of natural gas. According to IEA the production of hydrogen by using fossil fuels is responsible for carbon dioxide (CO_2) emissions of about 830 million tonnes carbon dioxide per year ($MtCO_2$/yr), which is 2.3% of the global annual CO_2 emissions [12, 13]. The main routes for decarbonizing hydrogen production are by capturing and storing the otherwise emitted carbon (blue hydrogen) or by producing it with water electrolysis using green electricity (green hydrogen). The focus for this research is on green hydrogen. Apart form decarbonizing current hydrogen production green hydrogen also looks promising for applications in sectors which are hard to decarbonize like high temperature heat in industry, aviation and seasonal storage. The developments in power-to-hydrogen systems requires an enhanced hydrogen distribution network. Both demand and supply should be balanced, in order to avoid excess production of hydrogen in the second place. The access to low-cost electricity is of key factor for the profitability. It is desirable to test the hydrogen production in feasibility studies or pilot projects, which will be given in the next section.

1.4 Similar Initiatives

The idea of producing hydrogen from wind energy is being put into practice in multiple pilot project on the North Sea. An overview of representative projects for wind power to hydrogen in the North Sea is given below:

1. IJVERGAS project, multi-functional island, 2 GW electrolysis (NL)
2. PosHYdon pilot project, re-purposing Q13-a platform, 6 MW (NL)
3. HEAVENN, hydrogen back bone grid, 6-year project starting in 2020 (NL) [14]
4. NorthH2 project, electrolysis power plant, 4-10 GW (NL)

All these pilot projects or hydrogen production initiatives have one goal in common: to get familiar with offshore production and distribution of hydrogen. This study will perform three interviews with members of the first three projects mentioned above. The goal of these interviews is in the first place to determine both the opportunities and challenges for the business case of offshore hydrogen production. Secondly, to gain more technical knowledge in sizing a power-to-hydrogen system including gas infrastructure and electricity transmission.

1.5 Research Goals

The main focus in this research is to determine the optimal business case for production of hydrogen in offshore wind energy in the North Sea. On forehand, it seems beneficial for the business case to produce hydrogen by converting the excess electricity to hydrogen which would be otherwise curtailed. A techno-economic model is established to determine the energetic and economic benefits by integration of hydrogen in a wind energy power system. This model is called the Wind Hydrogen Simulation (WHS). A thorough literature study is required to determine the cost and size of a power-to-hydrogen in an offshore environment. Another goal is to obtain the advantages and disadvantages for power-to-hydrogen systems, for with interviews are conducted with industry experts. From these goals, a main research question and a set of sub-questions is derived:

Main Research Question
What is the optimal business case for an integrated power-to-hydrogen system for offshore wind energy hubs in the North Sea?

Sub-Questions

1. How is the European energy market developing and what are the trends in the demand for green hydrogen?
2. How do the costs of a power-to-hydrogen system scale with different design choices and system dimensions?
3. What are the relevant operation modes and scenarios for a power-to-hydrogen system in the North Sea?
4. What are the energetic and economic benefits of the integration of a power-to-hydrogen system on artificial islands in the North Sea?

1.6 Method and Overview

In order to determine the optimal business case for offshore production of hydrogen, a techno-economic model is created that is able to maximize the energy production and thus the economic revenue as high as possible. This section gives an general approach for the evolution of the model and describes an appropriate framework for developing the model.

1.6.1 Energy modeling

Developing a model requires at least a modeling technique with an according application software. The technique which is most appropriate for this study is the System Dynamics (SD) modeling technique. SD is widely used in the energy industry with typical complex system variables with multiple feedback loops which affect the final energy policy formulation and management [15]. It is able to handle complex energy systems combining dynamic renewable energy and economics. The software used in this study to develop a SD model is the widely used commercial software Vensim. This software is able to convert system relations to a solvable set of differential equations. The model contains three main components: wind farm energy resource, electricity transmission and hydrogen production/transport. A schematic overview is shown in Figure 1.2.

1.6.2 Cost modeling

To determine the cost of energy or final cost per unit of mass of the hydrogen, the cost modeling is part of the total WHS model. This includes capital expenditure (CAPEX) and operational expenditure (OPEX). Figure 1.3 shows the schematic overview of all the cost components in this

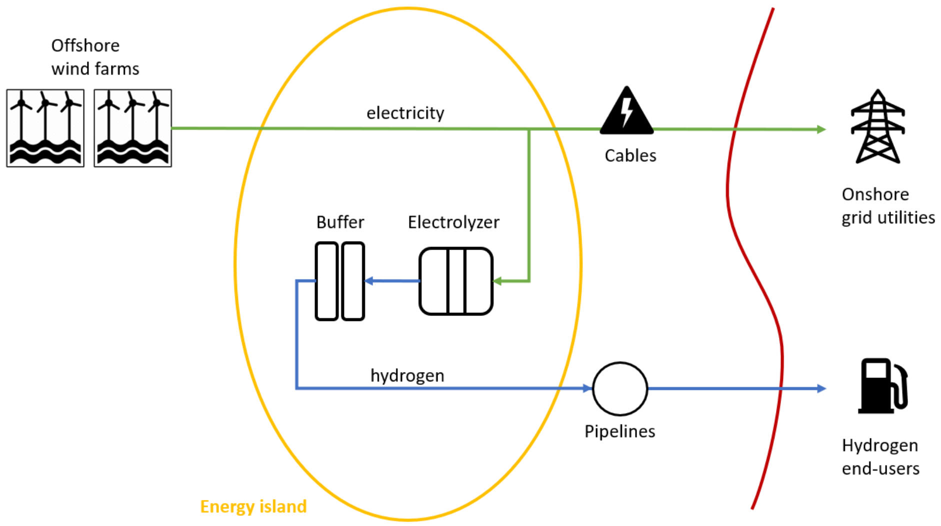

Figure 1.2: Overview of the energy hub concept including hydrogen production

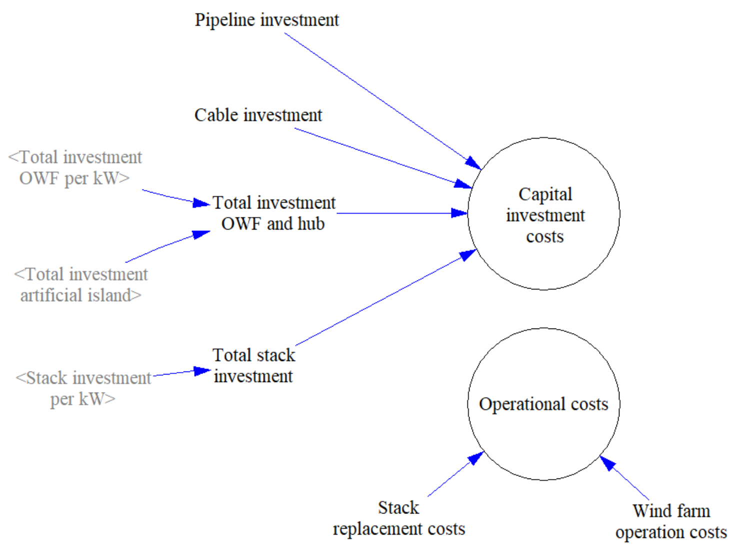

Figure 1.3: Schematic overview of cost modeling

model. The breakdown of the costs consist of energy generation, utility costs and transportation costs. Parameters which are likely to affect the final results are (mean) water depth and the route distance to onshore landing points.

1.6.3 Overview contents

An overview is given for the contents of this thesis. Chapter 2 performs a market evaluation to determine the asset cost of hydrogen for the power-to-hydrogen system to be investigated in this research. In Chapter 3 the crucial system components are determined and the capital and operational costs are estimated. An approach to determine the revenue streams for the system are derived in Chapter 4 by creating three operation modes and obtaining the relevant performance indicators. In Chapter 5, the WHS model is tested by applying several scenarios and the results are analyzed and discussed. In addition, two small case studies are performed. The most relevant conclusions are derived in Chapter 6.

Chapter 2

Market analysis

This chapter covers a brief market analysis for both electricity and hydrogen. The current trends with according prices are discussed and prognoses in supply and demand are defined towards 2050. Goal is to analyze the electricity market and discussing both the requirements and potentials for producing green hydrogen.

2.1 Curtailment

Wind energy curtailment usually occurs when current wind power exceeds the demand load. During this conditions a transmission system operator (TSO) shuts down multiple wind turbines within the wind farm to lower the power load on the electrical grid. This reduces the power factor of a particular wind farm, because annually energy is curtailed. This could be considered as *technical* curtailment. For European countries such as Germany, this curtailment levels are high and still increasing due to the large share of wind energy in the total energy mix [16]. In future this curtailed energy could be saved by integrating a power-to-gas system to the renewable energy system such as the system considered in this study. In a energy market perspective, it is key to balance the market by involving all participants. Curtailment in general needs to be a service to the energy system by dispatching down power output. On the other hand, some level of curtailment may be economically rational and sensible from a system operation perspective.

The curtailment levels demands for energy storage facilities, by either storing electrical energy or combining renewable energy with energy conversion technologies (power-to-X). In case of a power-to-hydrogen system, a hydrogen market should be available at which a producer of green hydrogen is able to sell its energy for a competitive bid price. Ideally, the hydrogen market has the same balanced level in offer and demand as the electricity market. In other words, in periods of high probability for curtailment, the bid price for hydrogen should be high in order to avoid curtailment and to improve grid stability. The next section will discuss the hydrogen market potential in the near and far future. In addition, the electricity price trends are discussed and analysed.

2.2 Hydrogen Market

2.2.1 Potentials

In the previous years, multiple consortia and projects such as the North Sea Wind Power Hub (NSWPH) and the consortium Offshore Service Facilities (OSF) are established to further investigate the technical and economic feasibility of the Hub & Spoke (H&S) concept. Both studies have mentioned to add an additional power-to-gas installation to provide energy system flexibility and avoiding curtailment. However, none of them has further investigated the technical and economic benefits of integrating such a power-to-gas system into island hubs on the North Sea. A distinction has to be made between on-purpose production of hydrogen and hydrogen production for stability purposes. In case hydrogen is produced by electrolysis using renewable electricity, one is able to provide 'green hydrogen'. Nowadays, over 95% of the hydrogen consumed by industry, is produced by steam reforming method from fossil fuel stocks [17]. A replacement of fossil fuels demands a transition to electrolysis in order to provide hydrogen and thus an increased demand for renewable energy capacity.

The first purpose for green hydrogen is to solve grid congestion due to an surplus of renewable energy penetration. Providing flexibility services to different electricity markets in Europe could significantly improve the business case of electrolyzers. Secondly, the desired decarbonization in the energy intensive industry and transport sector could drive down the cost for green hydrogen. The cost of green hydrogen produced from offshore wind in Europe starts about 6 USD per kgH_2 (€$_{2020}$ 5.34 per kgH_2) in 2020 and is expected to decline by 2030 to approximately USD 2.50 per kgH_2 (€$_{2020}$ 2.23 per kgH_2) [12]. This value is mainly driven by scaling electrolyzer manufacturing and increased efficiency of electrolysis.

2.2.2 Competition

For the production of hydrogen, the profitability of a power-to-hydrogen system is highly dependent on the wholesale market price of hydrogen. To define an asset price of green hydrogen, a comparison should be made with current available technologies. The two mature technologies available today for large-scale hydrogen production are steam methane reforming (SMR) and autothermal reforming (ATR) in combination with carbon capturing storage (CCS). SMR/ATR with CCS are defined as the short term solution in decarbonizing the industry sector. However, these technologies are unlikely to expand in scenarios towards 2050, since CCS facilities are limited in Europe. The International Energy Agency (IEA) published a report regarding the future of hydrogen in which they defined the potentials for hydrogen in 2030 globally [12].

On the demand side, IEA stated that it should be technically feasible to produce enough hydrogen for the industry in the long term. However, this would require a vast amount of low carbon electricity around 2500 TWh per year (10% of global electricity generation today). This would only be economic viable with policy support at low electricity prices. Figure 2.1 shows the asset prices of hydrogen in comparison with mature hydrogen production technologies. As can be seen, the electrolysis from renewable has a high combined sensitivity mainly induced by the fuel cost. The result is a high variance in cost per mass of hydrogen ranging from approximately 2 USD/kgH_2 to 4 USD/kgH_2.

2.3 Electricity Prices

2.3.1 EPEX trends

The European Power Exchange (EPEX) price is the spot price of electricity for which the supplier is able to sell an quantity of energy. Usually the day-ahead price is used in energy modeling systems. The day-ahead price distribution is a price based on historical and current demand data. On an annual base, the price of electricity shows dependency on the season, whereas more or less electricity is consumed or produced. Figure 2.2 shows the duration curve of the prices in € /MWh. As can be clearly seen, over the years from 2013 until 2019 the price tend to decrease on annual base and the difference between minimum and maximum spot price is increasing. The frequency of negative electricity prices is expected to increase due to expansion of installed renewable energy. This raises the demand for alternatives such as hydrogen production and storage. The next chapter will describe the design components as considered in this study.

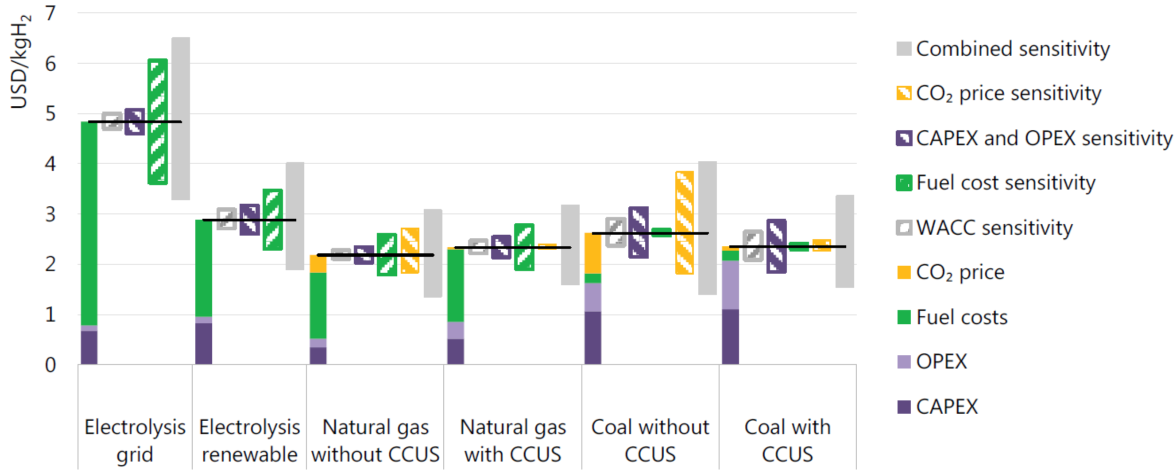

Figure 2.1: Hydrogen production costs for different technology options, 2030. Assumptions refer to Europe in 2030, reprinted from [12]

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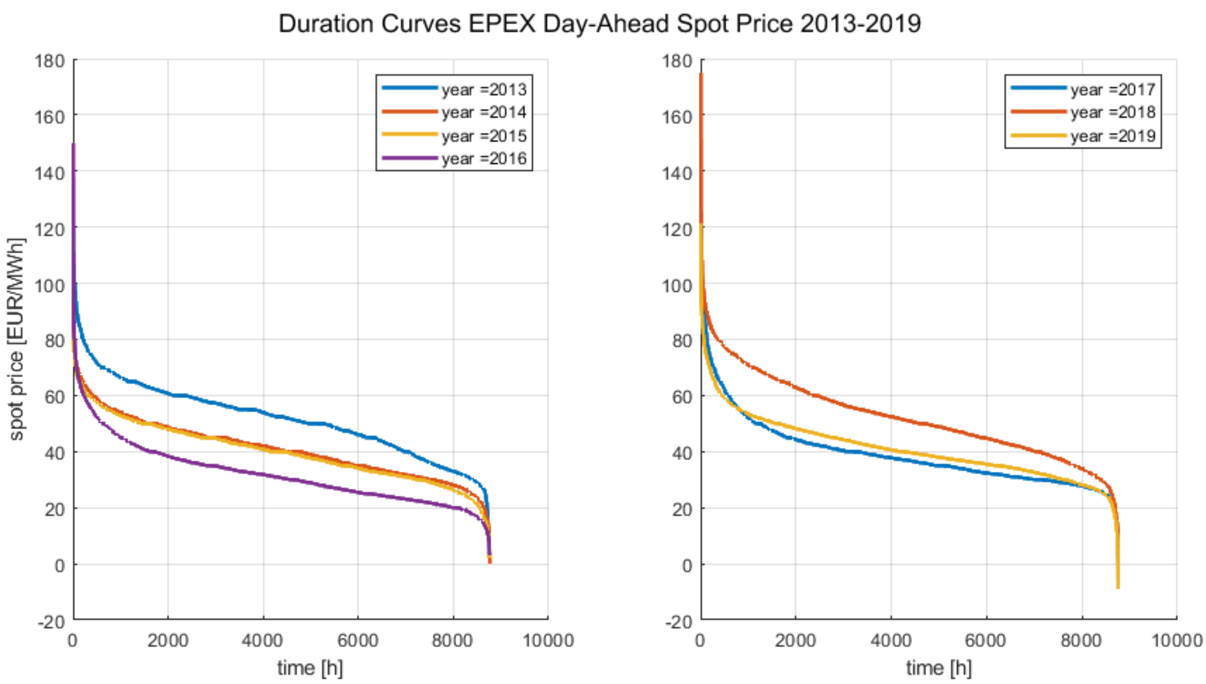

Figure 2.2: Duration curve for historical hourly EPEX day-ahead price data for years 2013-2019, retrieved from ENTSO-E Transparency Platform and Nord Pool Group [18, 19].

Chapter 3

Design Components

In this chapter the design criteria (size/efficiency) and the total expenditure are determined for the power-to-hydrogen system consisting of five main components: energy hub, offshore wind farms, water electrolysis, gas infrastructure and electricity submission. First of all, for each individual component the relevant technical specifications and assumptions are determined. Secondly the implication to the WHS model is described and explained. At last the expenditure is estimated based on literature study and values from interviews conducted during this project.

3.1 Energy Hub

3.1.1 Functions

The main functions for the energy hub considered are energy transmission and gas transportation. Additional functions could be storage and employees facilities for operation purposes. In this study it is tested whether the additional revenue stream of hydrogen is beneficial to total concept of an energy hub.

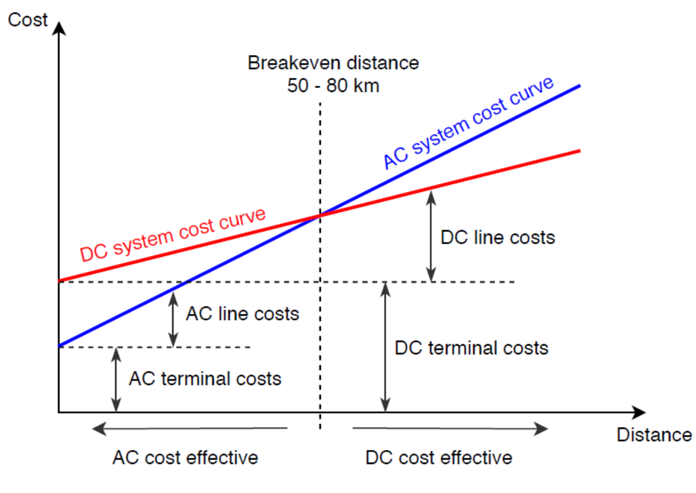

Figure 3.1: AC and DC system costs based on transmission distances, reprinted from [20]

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The distribution and transport of offshore generated wind energy requires a grid connection system (GCS). The most mature technology applied for the latest wind farms in Europe is AC radial, which is the standardised grid connection for TenneT. This connection submits electricity to shore by using 220 kV AC subsea cables with a 700 MW offshore transformer substation [5]. As the installed capacity of individual wind farm sites are increasing at location further offshore, DC radial is the second viable grid connection system. This technology has typical low cable production costs and induced energy transport losses, compared with AC radial. However, the substation platform with AC/DC converters and transformers are expensive. Moreover, a HVDC connection becomes more cost effective for distances further offshore. The break-even distance is in the range of 50-80 km, see Figure 3.1 [20].

The third option, which is able to combine both AC radial and DC radial grid connection, is the Hub & Spoke concept. This concept uses HVDC export connections, because these hubs are usually placed further offshore. The economies of scale play an important role for larger wind farms.

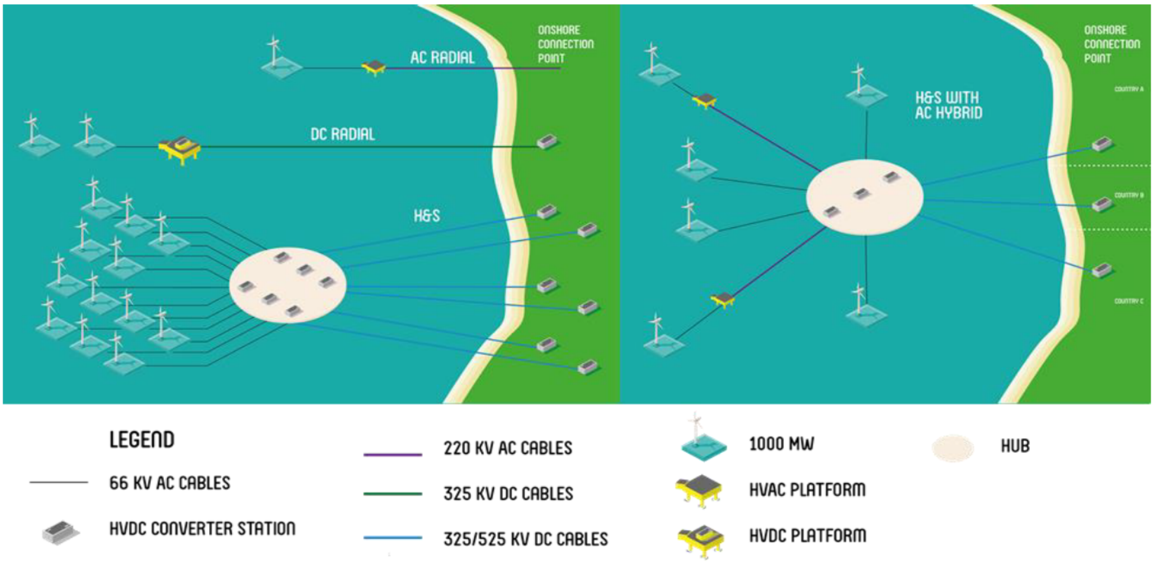


Figure 3.2: Grid connections systems including AC radial, DC radial and Hub & Spoke, reprinted from [7]

Concluding, the artificial island is originally hosting grid connection components and offers a central place from which wind farm maintenance can be executed. The main function which will be tested and analysed in this study is the electricity conversion to hydrogen by water electrolysis, see Section 3.3.

3.1.2 Expenditure

This section discusses an estimation of the cost for an island. The pure civil works to create an offshore artificial island is retrieved from NSWPH study 'North Sea Offshore Wind Farm Locations Post 2030' [6]. In Figure 3.3 the lookup table is given for the costs of the island civil works with varying wind capacity and water depth. For the WHS model, the cost formula behind these values is used. The OPEX for the artificial island is set fixed, 11 M€ for a 12 GW connected installed wind capacity. Capital and operational expenditure regarding additional user functions on the island such as wind farm maintenance facilities, harbour and airstrips are included in this cost prediction. It is assumed that this approximation of the costs is sufficient, since the main focus in this study is on the added benefit of electrolysis to the hub.

3.2 Offshore Wind Farm

3.2.1 Wind power generation

Since this study focuses on future scenarios for 2030 and later, the wind turbine specifications are expected to be improved regarding the latest developments in wind energy industry. According

size [GW]→	4 GW	6 GW	8 GW	10 GW	12 GW	14 GW	16 GW
availability [%]→	98.00%	98.25%	98.50%	98.75%	99.00%	99.25%	99.50%
Depth [m] ↓						Cost of island civil works [M€]	
15	1704	1779	1854	1941	1966	2118	2140
20	1790	1872	1954	2049	2078	2242	2268
25	1906	1996	2086	2190	2222	2400	2430
30	2060	2158	2256	2369	2405	2598	2631
35	2228	2335	2441	2564	2604	2812	2849
40	2411	2526	2641	2774	2818	3043	3084
45	2608	2733	2857	3001	3048	3290	3335

Figure 3.3: Cost of civil works for the artificial island with connected wind power ranging from 4-16 GW, reprinted from [6]

to the annual statistics by WindEurope, the average capacity factor for operating offshore wind farms in Europe is 38 percent [3]. The capacity factor is calculated in the WHS model and differs per geographical location with capacity factors above 50 percent are assumed to be reasonable for future offshore wind farms. A study performed by RVO and TKI Wind op Zee considers the installation and commissioning of Dutch wind farms after 2025 such as IJmuiden Ver. For this future wind farms an expected single wind turbine capacity of 15 MW [21] is used. Therefore, the reference wind turbine in this study has an installed capacity of 15 MW with a rotor diameter of 250 meters and hub height of 150 meter.

3.2.2 Expenditure

The cost of an entire wind farm can be divided in 4 main categories: development, construction, operations and decommissioning. The total expenditure for offshore wind farms depends on multiple variables, since it is highly dependent on investment conditions. In 2019, the Dutch ministry PBL Netherlands Environmental Assessment Agency did an assessment to the cost of offshore wind energy, considering the designated wind farms sites as opened for tendering in the Dutch Offshore Energy Roadmap 2030 [22]. Based on a 25-year economic lifetime they estimated the investment costs of the wind farm sites Hollandse Kust, Ijmuiden Ver and Boven de Wadden Eilanden to be 1600-1700, 1850 and 1900 €/kW. The operation and maintenance costs are ranging from 41 to 64 €/kW/year. As a reference, the leading Danish wind farm company Ørsted won the Borssele I & II tender in 2016 with a estimated cost of energy of 72.7 €/MWh, whereas the most recent Borssele sites III & IV were tendered for 54 €/MWh. These cost are expected to drop for wind farms after 2030 due to learning curve implications, becoming 36-39 €/MWh [6]. In Table 3.1 the cost formulas for the capital investments are given for materials and construction of the wind turbine, substructure and intra-array cables. Based on the formulas and values given in the table, the estimated cost for the offshore wind farm after 2030 is set to 1238 €/kW.

3.2.3 Model

Modeling and predicting the energy output of a wind farm is rather complex. Nowadays, advanced numerical software is available to perform wind farm resource assessments. The wind farm energy production in the WHS model is estimated by inserting wind resource data for the Dutch offshore wind climate. In the WHS model, a wind farm power curve is implemented which is reconstructed from wind farm simulation results. This wind farm curve is a result of

Component	Specification	Capital investment [M€]	Reference
Single wind turbine	Nominal power of 15 MW	14	[7]
Substructure	Monopile, TP and tower	$0.0018 * H_w^2 - 0.0056 * H_w + 5.1183$	H_w: water depth, [23]
Intra array cables	66 kV XLPE AC cable	0.22 per km	[7]

Table 3.1: OWF cost formulas for reference wind farm with installed capacity of 1 GW [6]

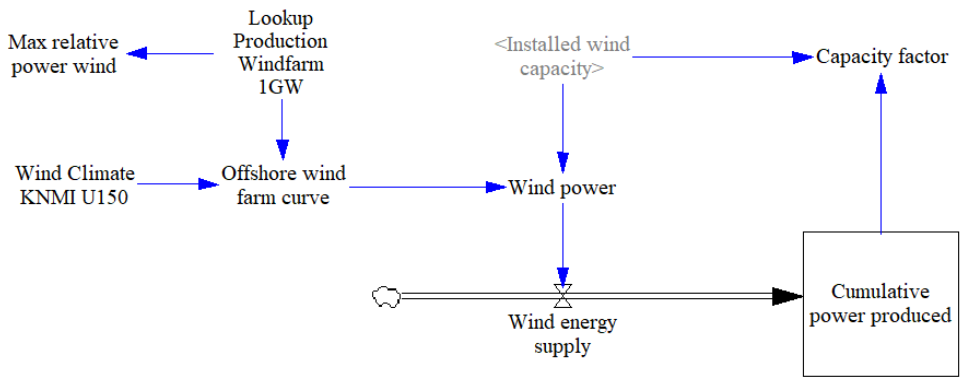


Figure 3.4: Modeling wind energy input

a wind farm simulation performed by TNO for an offshore wind farm depending on the local Weibull shape factor. This Weibull shape factor is a parameter which indicates the width of the wind speed distribution and can be calculated from the available wind data at the specific location of analysis. The Weibull shape factor k can be calculated by using Equation 3.2 with $\overline{V}$ the mean of the wind velocity vector V and σ_V the standard deviation of the wind velocity vector V [24]. The value for k is used to pick the corresponding wind farm power curve, which is retrieved from data available at Witteveen+Bos as part of the NSWPH project. In Section 4.2.1 this is further elaborated. The rate function 'Wind energy supply' forms the input energy for the remaining of the system. From the cumulative power produced, the annual capacity factor can be calculated by dividing the cumulative wind energy by the total energy produced if the turbines are running on nominal power for an entire year.

$$\sigma_V^2 = \left(V - \overline{V}\right)^2 \tag{3.1}$$

$$k = \left(\frac{\overline{\sigma_V}}{\overline{V}}\right)^{-1.086} \quad \text{for } 1 \leq k \leq 10 \tag{3.2}$$

3.3 Water Electrolysis

3.3.1 Electrolyzer requirements

In order for power-to-hydrogen systems to become efficient and economically viable it should meet five main requirements: (1) high efficient production of hydrogen; (2) fast response to power fluctuation; (3) very low minimal load for stand-by; (4) high-pressure operation to reduce the cost of hydrogen compression; and (5) long durability and lifetime [25].

The power-to-hydrogen ($P2H_2$) is in general characterized as a power-to-gas (P2G) system. A

P2G system is known as a more comprehensive terminology for all technologies concerned with conversion to gas by using excess or renewable electricity. Within these conversion chains, the production of hydrogen from water electrolysis is most commonly executed, since it can be used directly as a final energy carrier or can be used for production of methane by adding carbon dioxide from carbon capturing storage (CCS).

3.3.2 Stack sizing

The electrolyzer stack determines the core of the entire P2G system. The main function of the electrolyzer is converting water and electricity into hydrogen and oxygen. The two main technologies used are proton exchange membrane (PEM) and alkaline electrolysis (AEL) whereas AEL is a settled technique and in PEM technology research is still being done. In terms of start up time and ramp up times, they both have similar values in order of seconds. The operation and maintenance for the alkaline system requires higher intervals, which is caused by frequently refilling the electrolyte solution. Alkaline technology requires less rare metal based materials which partly results in lower production costs. For offshore appliances the alkaline seems to be most suitable since it is already available for large electrical power levels. On the other hand the membrane used in PEM technology is promising and research is expanding.

The CAPEX per unit of installed capacity depends on technology and producer. In Table 3.3 the technical specification of a AEL and PEM electrolyzer stack array with capacities above 25 MW is given, the NEL A3880 and Hylyzer-5.000. The nominal hydrogen production of the NEL A3880 electrolyzer is substantially lower (3880 Nm^3/h against 5000 Nm^3/h). The AEL electrolyzer has a lower electrical energy consumption but it has typically lower current densities with respect to PEM technology. This is explained by the concept of the zero-gap PEM cell, where the porous electrodes are directly attached to the polymer electrolyte [26]. This reduces the ohmic losses obtained across the polymer electrolyte, which enables the PEM cell to operate at high (several A cm^{-2}) current densities [27]. In the next sections, PEM technology is used as the technology of consideration.

3.3.3 Electrolyzer efficiency

During the process of splitting water into hydrogen and oxygen, part of the energy required is released during the formation of oxygen and hydrogen molecules. The energy released can be explained by thermodynamics, whereas the minimum required energy for water splitting can be calculated from the Gibb's free energy (Δ G). However, the process of water splitting induces a change in entropy (ΔS) which adds to the total enthalpy (ΔH) of the process. The potential equation to calculate the minimum required voltage (V_{TN}) is given in Equation 3.3 [9].

$$V_{TN} = \frac{\Delta H}{nF} = \frac{\Delta G}{nF} + \frac{T\Delta S}{nF} = 1.48V \tag{3.3}$$

where V_{TN} is the thermo-neutral voltage, n the number of electrons involved (n = 2), F the Farady constant ($9.65{\cdot}10^4$), T the absolute temperature of the process. At standard conditions the change in Gibb's free energy is $\Delta G = 237.22$ kJ mol^{-1} of change of enthalpy is $\Delta H = 285.84$ kJ mol^{-1}, the minimum required cell voltage is V_{TN} = 1.48 V. The water electrolysis efficiency can be calculated by either the higher heating value (HHV) or the lower heating value (LHV). In Equation 3.4 the higher heating value is used to calculate the electrolyzer efficiency at nominal production rate.

$$\eta_{sys} = \frac{HHV_{H_2}[kWh/kgH_2]}{E_{IN}[kWh/kgH_2]} \tag{3.4}$$

The typical higher heating value (HHV_{H_2}) for hydrogen is 39.4 kWh/kgH_2 (141.7 MJ/kg) with an electrical energy consumption (E_{IN}) for PEM in the range of 56.4-60.9 kWh/kgH_2 (5.0-5.4

kWh/Nm^3) at normal conditions (0 °C and 1 atm). Thus using Equation 3.4, the HHV efficiency ranges between 65 and 70 percent.

Manufacturer	**System model**	**Installed power [MW]**	**Nominal production rate H_2 [Nm^3/h]**
Siemens	Silyzer 300	27.5	3830
Hydrogenics	HyLYZER-5000	25	5000
Proton Onsite	M400	2	400
Siemens	Silyzer 200	1.25	225
ITM Power	HGas1000	1.03	215

Table 3.2: Overview of PEM manufacturers with characteristics [25]

Specifications	**(1) NEL A3880**	**(2) Hylyzer-5.000-30**	**Notes**
Technology	AEL	PEM	
Manufacturer	NEL	Hydrogenics	
Total nominal power (MWe)	28.6	25	(1): 13 units of 2.2 MW each
Nominal production rate (Nm^3/h)	2400-3880	5000	
Ouput pressure (bar)	30/200	30	
Elec. consumption (kWh/Nm^3)	3.8-4.4	5.0-5.4	
Water consumption (l/Nm^3)	0.9	1.4	
Area required (m^2)	770	426	(2): 10x (12.2 x 2.4m) + 5x (11.1 x 2.4m) containers

Table 3.3: Typical properties of PEM and alkaline electrolysis technology. Reconstructed from [28, 29]

3.3.4 Expenditure

Over-sizing could be a problem while designing an electrolysis system. Depending on the purpose of the hydrogen system in terms of operation mode, the capacity over-sizing leads to higher CAPEX levels. Therefore, the CAPEX values are usually expressed in cost per installed capacity (€/kW). The U.S. research department of energy NREL, performed a cost estimation for 200 kW and 1 MW PEM electrolysis systems [30]. They used both literature and commercial sources to determine the total construction cost, consisting of stack, balance of plant (BOP), operational and installation costs. The price of a MW-scale PEM electrolysis system was estimated to be around 890 €$_{2020}$/kW ($ 1,000/kW) by 2030, and 490 €$_{2020}$/kW ($ 550/kW) by 2050. This price, however, can be reduced to 620 €$_{2020}$/kW and 345€$_{2020}$/kW for multi-MW system in 2030 and 2050, respectively. Hou et al. performed an case study for an offshore wind and electrolytic hydrogen storage system in Denmark [28]. A cost optimization model was established for the sizing and equipment selection of a P2G system including market interaction.

Another recent study by Van Nguyen et al. made an economic and technical prediction for PEM electrolyzers in a power-to-hydrogen system in 2030 [31]. They estimated that the CAPEX for the initial plant is 600 €/kW with stack replacement cost of 150 €/kW after a certain stack operation time of 12.5 years. The OPEX over the total lifetime of 25 years for such a system was calculated to be 300 €/kW (2% of CAPEX per year). The most valuable component in PEM water electrolysis is the cell stack. The membranes in the stack together with the bipolar plates are the most expensive and thus most valuable parts of the electrolyzer.

In the research of Saba et al. it was concluded that today's estimations for future investment costs (2030 and later) of PEM electrolyzers is in the range of 397 €/kW and 955 €/kW [32]. The balance of system (BOS) is covering all subsystems which are crucial for the electrolysis stack to function properly. It differs among studies performed in the past, which subsystems to take into account. A breakdown of the capital cost for a typical PEM electrolysis system is shown in Table 3.4. The membrane is usually part of a membrane electrode assemblies which consist of a membrane, ionomer solution, anode and cathode electrocatalysts being responsible for 29 percent of the total costs. The most common type of membrane is the Nafion© due to it proper performance in terms of conductivity and thus higher achieved current densities (>2 A cm^2). Therefore, it is concluded that PEM will be the mature technology for electrolysis systems in 2030 and thus PEM is considered in the WHS model created in this study.

Besides the main electrolyzer stack, all other auxiliary components can be classified as balance of plant (BOP) which accounts for 40 percent of the total electrolyzer system capital costs according to Table 3.4. The BOP is composed of several subsystems and the main parts for a system of order magnitude MW are listed below [30]:

- Power supply: rectifiers and voltage/current transducers.
- Deionized water circulation system: oxygen separator tank, circulation pump, piping, valves and instrumentation, and controls.
- De-ionized water circulation system: oxygen separator tank, circulation pump, piping and valves.
- Hydrogen processing: dryer bed and hydrogen separator.
- Cooling: plate heat ex-changer, cooling pump and dry cooler.

Component	**System cost (%)**
Bipolar plates	31
Membranes/collectors/electrocatalysts	29
Balance Of Plant (BOP)	40

Table 3.4: Breakdown of capital costs for a typical PEM electrolysis system. [33]

In Table 3.5 an overview is shown for the results of the literature research and these values have been used as a starting point for testing the simulation model WHS, see Chapter 4.

3.3.5 Model

The electrolysis process is modeled in the WHS model. In Figure 3.5 the schematic overview is displayed. The main function is represented in 'Power to hydrogen' calculating the remaining power available for electrolysis, see Equation 3.5.

$$\textit{Power to hydrogen} = \textit{Wind energy supply - Electrical power to market - Curtailment} \quad (3.5)$$

where the Obviously, the electrical energy applied to the electrolyzer can be simulated as two separate functions 'Conversion losses' and 'Hydrogen to buffer'.

The hydrogen buffer is implemented mainly to store the hydrogen generated at periods where the stack load is on maximum capacity for longer periods. This is usually the case when the wind power is at maximum. In addition, it gives the opportunity to size both cable capacity and pipeline capacity slightly lower. To determine the minimum required buffer capacity, the variable 'Overproduction buffer time' is created which indicates the duration of peak stack power when the buffer is expected to be full.

Assumptions	Value	Units	Note/Source
Total lifetime electrolyzer	25	years	[31]
CAPEX electrolyzer system	600	€ / kW	[31]
OPEX electrolyzer system	300	€ / kW	Total OPEX over total lifetime of 25 years, [31]
Stack replacement costs	150	€ / kW	Replacement interval of 12.5 years, [31]
Efficiency electrolyzer	65-70	%	Based on HHV efficiency, normal conditions.
Hydrogen price, NL	2.6	€/kg	CEER expectation for 2030, incl. green certificates, reference electricity price 40 €/MWh, [34]

Table 3.5: Summary of relevant technical and economic values for electrolyzer specifications from literature

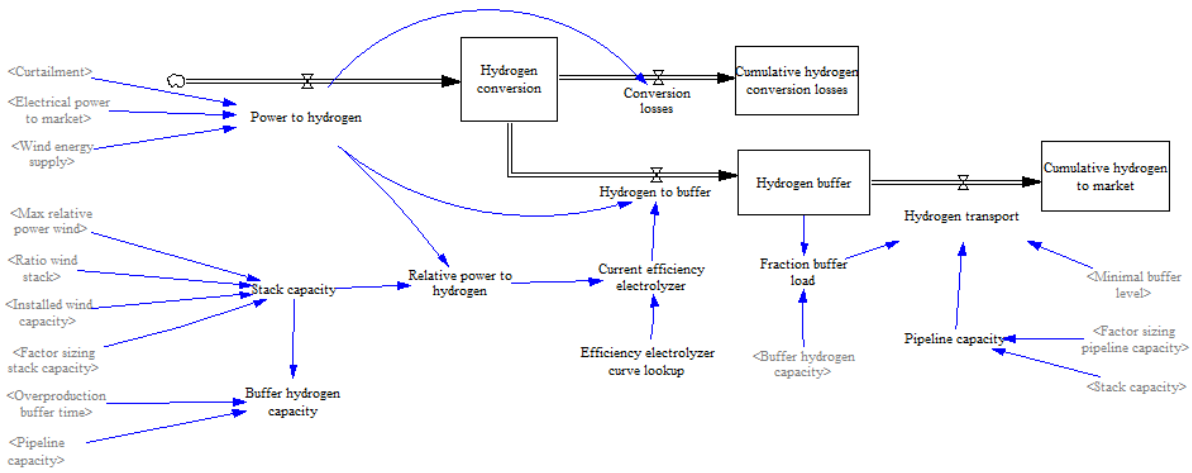


Figure 3.5: Schematic overview of the electrolyzer modeling including hydrogen buffer

3.4 Gas Infrastructure

3.4.1 Pipeline specifications

Extraction of natural gas in large volumes has led to a highly developed gas transport system. Globally the total distance of natural gas pipelines is 3 million km whereas hydrogen pipelines are close to 4500 km around the world today [35]. The hydrogen pipelines are used in chemical feed stock for commercial operations. Gas pipelines in general are used for transmission of chemical energy since it has typical low operational costs and lifetimes are usually more than 50 years. The installation of gas transport network line in the North Sea started in 1980 and since then the length of pipelines has increased rapidly as more platforms were being commissioned. Compatibility of natural gas pipelines for hydrogen transmission depends mainly on the type of steel used in the pipeline and the purity of hydrogen being transported.

Recent studies in the Netherlands have discovered that small changes are required in order to use the existing natural gas grid for transmission of hydrogen to end-users. The latter studies mainly considered the low pressure infrastructure network for local distribution, whereas polymer based pipelines are used for end-user gas distribution. In case of large offshore hydrogen production levels, dedicated sub-sea hydrogen pipelines are likely to be constructed in addition to the existing infrastructure. However, the exact size and costs of such dedicated hydrogen pipelines are yet unknown. According to a participant of the Ijvergas project, the electrolyzer stack output pressure of 30 bar is sufficient for transporting hydrogen gas to shore by pipeline (interview with IntecSea, see App. A.2). To get an insight in the main differences in transporting natural gas or hydrogen, the physical properties are shown in Table 3.6.

	Hydrogen (H_2)	Methane (CH_4)
LHV (MJ/Nm^3)	10.8	35.8
LHV (MJ/kg)	120	50
ρ@ 1 bar, 18 °C (kg/m^3)	0.0832	0.664
ρ@ 100 bar, 25 °C (kg/m^3)	7.67	79.3
Flame speed (cm/s)	170	38.3

Table 3.6: Physical properties of both hydrogen and methane, Engineering Toolbox

3.4.2 Expenditure

Several projects have been done in the past for large offshore transportation of natural gas by pipelines. The most common one is the Nord Stream Project 1 and 2 which comprises a 1200 km offshore pipeline distributing natural gas from Russia to Europe [36]. A comparison between the projects and the specific CAPEX as a function of distance is shown in Figure 3.6.

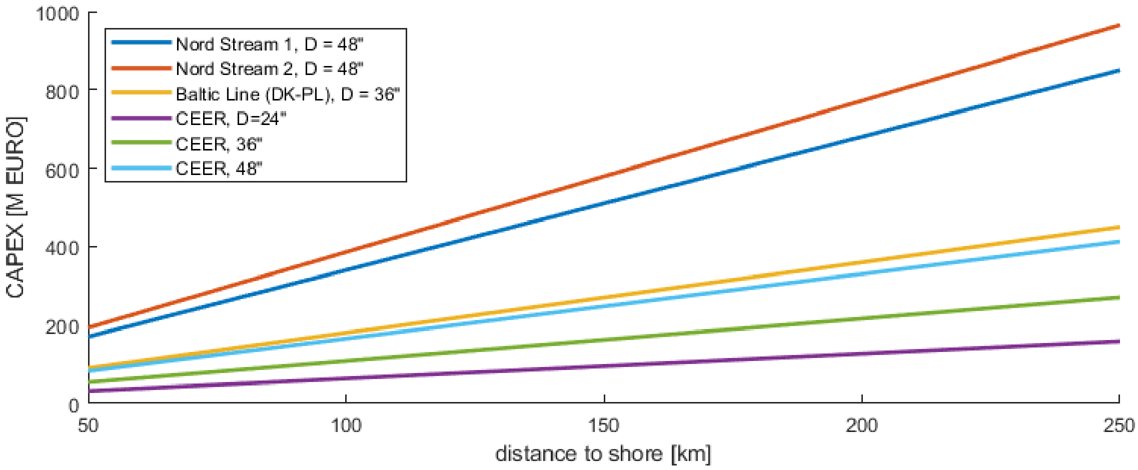


Figure 3.6: CAPEX cost for projects in Europe. Reconstructed from a CEER study and 'The real financial cost of Nord Stream 2' [34, 36].

From a pipeline cost estimation performed by TCB or CEER, the total pipeline construction cost for offshore transport of gas is determined. This can be expressed as a function of diameter giving the total cost per unit distance. They validated the results with the approximation from a ACER study in 2015 with an average unit price in the range of 42-44 € /inch/m which includes all implementation and construction costs [34]. Saadi et al. did a research to the relative cost of hydrogen pipelines with respect to natural gas pipelines concluded that the estimated increase in cost of constructing hydrogen pipelines is 10% [37]. Current hydrogen pipeline operating pressures are in the range of 10-30 bars. For a hydrogen pipeline with pipe diameter of 36 inch, operating pressure of 30 bar, fluid velocity of 15 m/s, the total cost of pipeline per km is 1.77 M $€_{2020}$ per km (3.20 million \$ per mile) [37]. Another study in 2019 defined an equation for cost versus capacity for pipelines with nominal fluid velocity of 10 m/s and fixed hydrogen density of

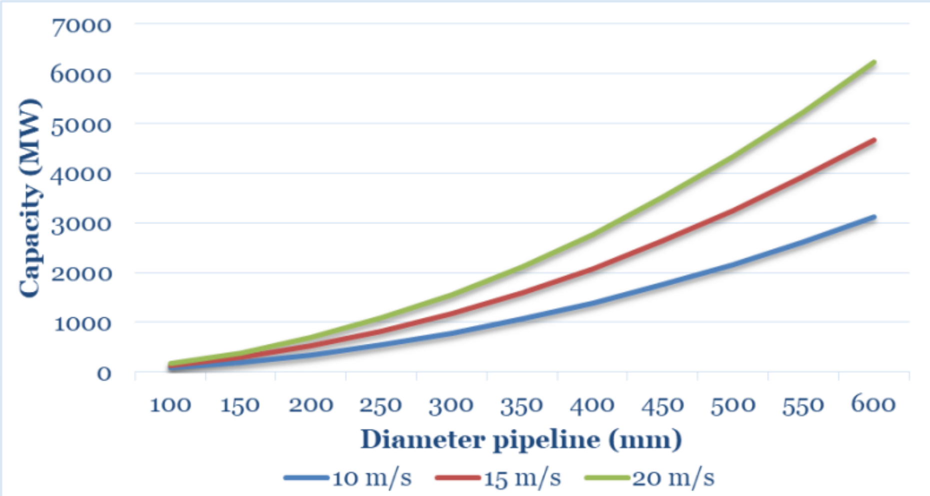


Figure 3.7: Power of gas pipeline vs diameter, reprinted from [34]

5.7 kg/m^3 [38]. The investment cost for such a dedicated hydrogen pipeline is given in Equation 3.6 [38].

$$I_{PL} = 180 * PC + 408 \tag{3.6}$$

with PC [GW$_{H_2}$] the pipeline capacity and I_{PL} [€/m] the specific pipeline investment costs. The pipeline capacity in this study is linked to the lower heating value of hydrogen (33.32 kWh/kgH_2) where 1 GW$_{H_2}$ corresponds to a mass flow of 8.34 kgH_2/s.

3.4.3 Model

The transport of hydrogen gas is modeled in the function 'Hydrogen transport', see Figure 3.5. This power of transport is basically determined by the pipeline capacity. The pipeline capacity is calculated by multiplying the 'Stack capacity' by the 'Factor sizing pipeline capacity'. The latter variable is used to avoid over-sizing the pipeline and thus avoiding induced rise in pipeline costs. The pressure drop over the pipeline is neglected, since the hydrogen is transported by using natural gas pipelines at the nominal flow velocity in the range of 10-15 m/s. In the WHS model, the required pipeline capacity is calculated from the power curve in the CEER study the diameter of the pipeline can be found, see Figure 3.7. Using Equation 3.6 the estimated pipeline investment cost is calculated in the WHS model.

3.5 Electricity Submission

3.5.1 Cable specifications

For the electricity submission by electricity cables, the cables can be categorized by three types of cables for offshore wind farms: intra-array cables, inter-array cables and inter-connector cables. The sizing and cost of the inter-connector cables are considered for the main transport of electricity from the hub to onshore landing points.

Intra-array cables: Electrical power transmission from OWF plant to shore can be provided in two ways: High voltage alternating current (HVAC) and high voltage direct current (HVDC). HVAC is a mature technology in offshore electrical power transmission for OWFs until 2010 [39]. The high capacitance of submarine HVAC cables has led to additional charging currents, reducing the active power transmission capacity in long distances [40]. The most common solution to this problem is to install reactive power compensation units along the HVAC submarine cables, but these units are costly. On the other hand HVDC transmission is considered to be

most economically viable for distances above about 100 km.
Inter-array cables: These cables are used for transmission of electricity from the wind farm transformation substation to the energy hub. The mode of transportation is usually HVAC with 55 kV cables. The export cables offer the possibility to transfer and trade electricity between European markets are also of consideration for the energy hub concept. The largest cable available and operational since 2011, is the cable connection owned and operated by BritNed connecting the UK and the Netherlands with two 260 km long bundled cables with a capacity of 1000 MW at an operating voltage of 450 kV DC. The total investment cost were 600 M€ including BritNed Converter Transformer which brings it down to an investment price of 2.3 M€ /km [41].

3.5.2 Model

In Figure 3.8 the modeling for the electrical submission is shown. The cable capacity is first calculated by using the following formula:

$$\begin{aligned} &\textit{Cable capacity} = \textit{(1-Ratio wind stack)} * \textit{Installed wind capacity} * \\ &\textit{Maximum relative wind power} * \textit{Factor sizing cable capacity} \end{aligned} \tag{3.7}$$

with CC the cable capacity, RWS the the ratio wind stack being the desired ratio between electrolyzer capacity and WC the installed wind farm capacity. The factor sizing cable capacity is a model parameter to higher or lower the cable capacity if necessary. Maximum relative wind power is determined by the maximum wind power available after losses divided by the nominal installed wind farm capacity (WC). The cable capacity is the absolute limit for the function 'Electrical power to market'. The function rate 'Electrical transport' is the final result including the electrical transport losses, being 45 kW/km for a 2 GW HVDC cable [7]. The final cumulative electrical energy being transmitted to shore is stored in the level 'Cumulative electrical power to market'.

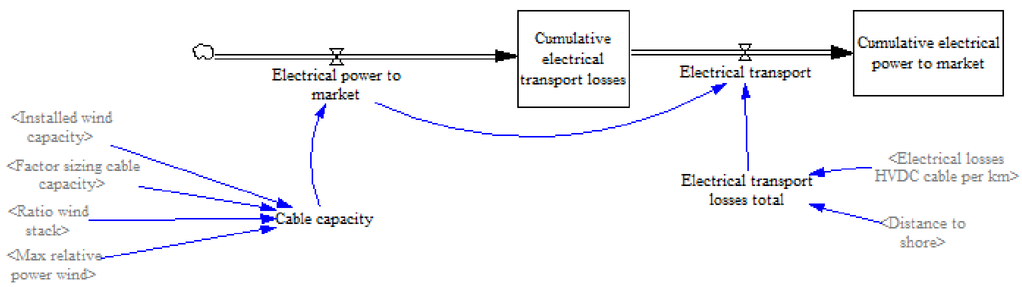


Figure 3.8: Schematic overview of the model for electricity submission

3.6 Total Expenditure

In Figure 3.9 the model calculation for the total capital and operational costs are shown. This section of the model performs the interaction between the total energy produced and the economic revenue by selling the energy to the market. The results are stored in the two levels 'Cumulative electricity economic revenue' and 'Cumulative hydrogen economic revenue'. The performance indicators Levelized Cost of Energy (LCOE) and Net Present Value (NPV) will be explained in Section 4.4.3.

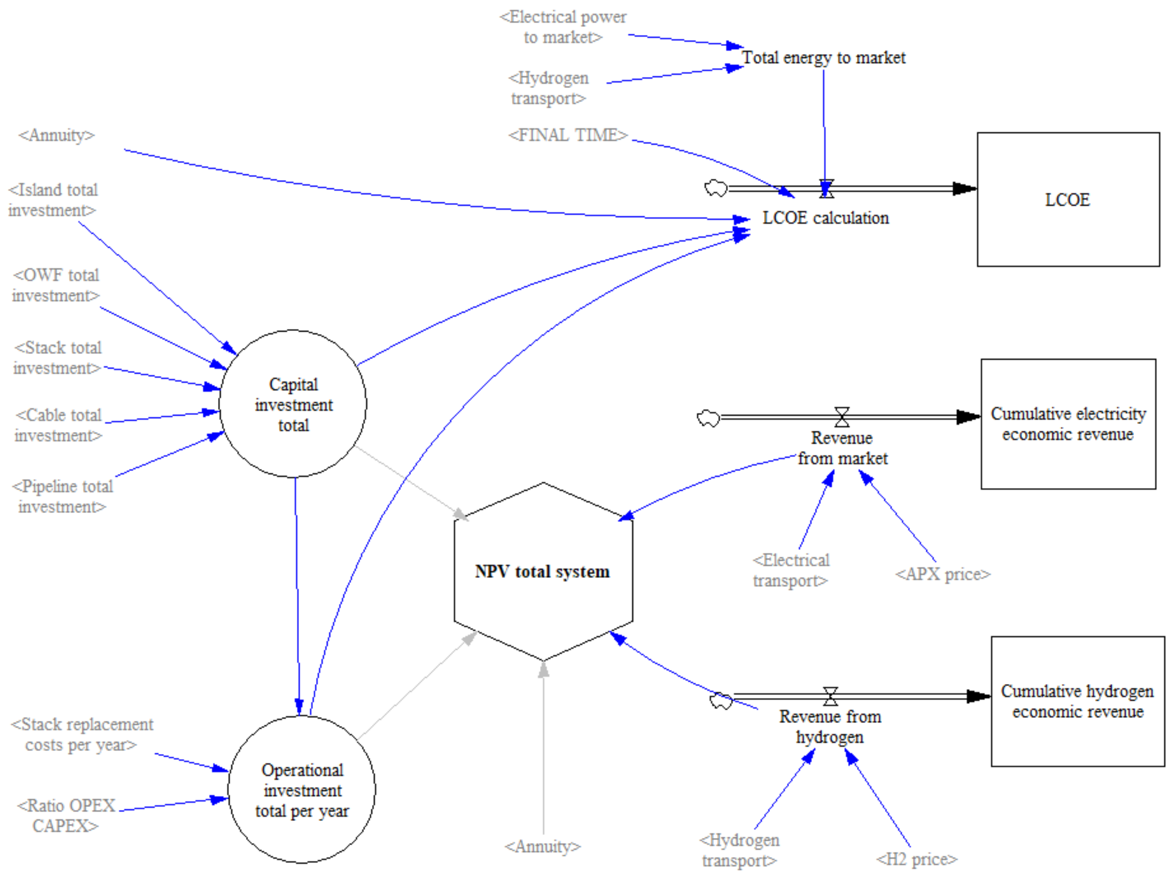


Figure 3.9: Cost modeling of the capital and operational expenditure of the system

Chapter 4

Modelling Energy

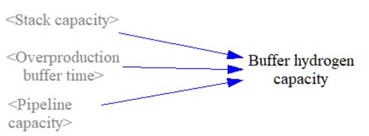
In the previous chapter, all system components were described and the expenditure of the system was estimated. These results will be part of the model as explained in this chapter, covering the operation modes before analysing the results in the next chapter. Within each scenario both technical and economical parameters are included in order to obtain economic benefits for the power-to-hydrogen system. The goal of this chapter is to describe the WHS model in more detail and to show the implementation of several operation modes.

4.1 Model Sub-Functions

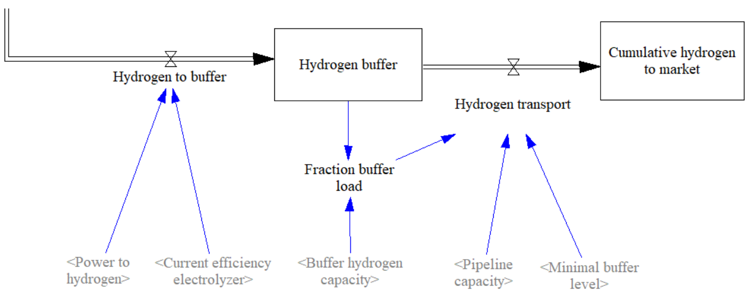
This section will give an overview of the main and sub-functions of the WHS model which are defined to be crucial for the final results. The three main functions related to electricity submission, hydrogen production and transport are explained in Sections 3.5.2, 3.3.5 and 3.4.3. For this section, the goal is to define and explain the sub-functions which improves the performance of the main functions and thus advances the overall performance.

4.1.1 Buffer

Within the WHS model, a buffer is introduced for energetic purposes. It is assumed to be crucial in withstanding high wind energy peaks, where both pipeline and electricity cable are operating on maximum power. An alternative should be to increase capacities, but this increases investment costs. Applying a hydrogen buffer after the electrolyzer allows for more continuous hydrogen flow through the pipelines. In Figure 4.1 both the calculation for the capacity (a) and the total buffering process including hydrogen transport through pipelines is given (b). The buffer capacity is calculated with the time of overproduction for the buffer which is an indicator for the expected duration of these peak wind loads. This number (in hours) is multiplied by the difference in stack and pipeline capacity. However, the duration of these periods of maximum production of hydrogen do vary over the years. At some point, the buffer is at maximum level and no hydrogen should be generated, thus the power to the electrolyzer is reduced.



(a) Buffer capacity model as representative in WHS model



(b) Hydrogen buffer modeling in WHS model

Figure 4.1: Buffer WHS modeling

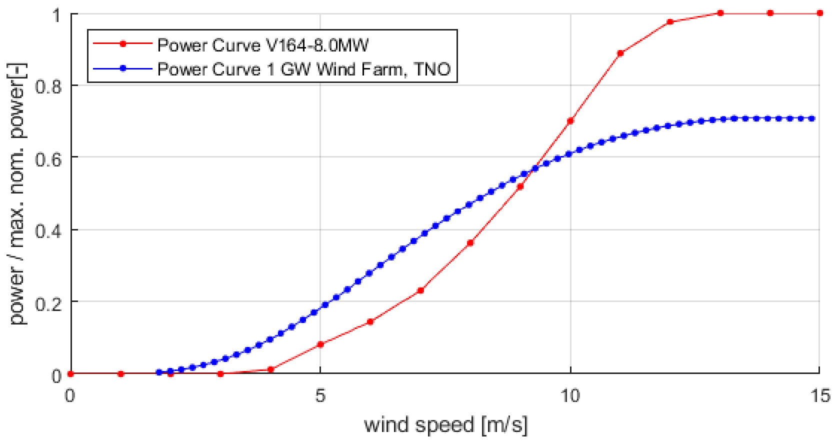


Figure 4.2: Power curves for the Vestas V164-8.0 MW turbine (red line) and a 1 GW wind farm (red line) with k=2.17.

4.2 Model Input

4.2.1 Wind farm power curve

The electric supply for this model will come from consecutive number of 1 GW wind farms. This will constitute the base line for this study, because wind farm size will be scaled up to capacities greater than 1 GW. The wind farm power curve is represented in Figure 4.2 (blue line) with on the vertical axis the wind farm power output relative to the nominal wind farm power (1 GW). This power curve includes wake losses within the wind farm and electrical energy losses in the intra-array cables. Thus, the power curve will never reach the maximum nominal power which is defined as the number of turbines multiplied by the nominal power of a single wind turbine. The power curve of the Vestas V164-8.0 MW wind turbine is used as a reference for the single wind turbine, because commercial performance data was available for this wind turbine model with a nominal capacity of 8.0 MW (red line in Figure 4.2). The cut-in wind speed is lower (approx. 2 m/s) for the wind farm power curve due to inter turbine wake effects.

4.2.2 Dutch Offshore Wind Atlas

The KNMI North Sea Wind Atlas is used to download a historical hourly dataset of the wind climate in the North Sea. The Dutch meteorology institute KNMI have reconstructed the wind speeds for 2008-2017 in the Dutch Offshore Wind Atlas (DOWA). Validated wind climate data from the weather data model HARMONIE-AROME is provided in a set of hourly wind climate data for a specific 2.5x2.5km grid cell for 17 heights ranging from 10 meters above sea level up to 600 meters above sea level [42]. In this study the DOWA data set is used at hub height of 150 meters for the time period 2013-2016.

4.3 Operation Modes

An operation mode in this study is characterized by the main operation approach for powering the electrolyzer stack. This affects the total energy production and economic revenue at the output of the power-to-hydrogen system. The three main operation modes are defined as base load, peak load and market optimized.

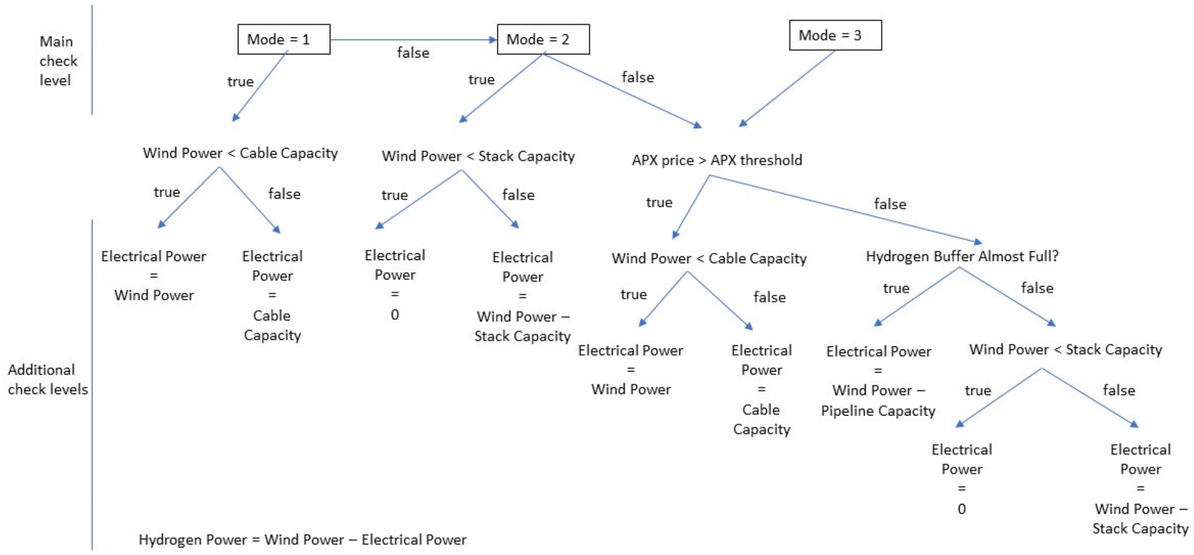


Figure 4.3: Schematic flow chart of model framework for operation mode 1,2 and 3.

4.3.1 Mode 1: Peak load hydrogen production

In case of *peak load hydrogen production* hydrogen is produced if the wind power is high or either reaching his maximum. In fact, the system is maximizing the electrical power which is limited by the cable capacity. The remaining electrical power available is loading the electrolyzer. This operation mode represents the situation at high wind power levels where the cable capacity is reached. The goal for this mode is to show how much energy can be saved, which was possibly curtailed otherwise.

4.3.2 Mode 2: Base load hydrogen production

The power-to-hydrogen system operating with a *base load hydrogen production* typically produces hydrogen at all times when wind power is available. The installed capacity of the electrolyzer stack affects the amount of wind energy loading the electrolyzer. Therefore, the stack capacity limits the amount of wind power converted into hydrogen. The remaining wind power is transmitted to shore by cable.

4.3.3 Mode 3: Market optimized hydrogen production

This mode basically combines mode 1 and 2 and adds a real-time optimization by comparing the current electricity price with a certain threshold. This threshold is a backward calculated mean market price or just a value for which it appears to be profitable to make hydrogen. Above this threshold the system decides to transmit as much electricity as possible. Below this threshold the system converts all available electrical energy into hydrogen. For all real-time comparisons applies that it should never excess the pipeline or cable capacity. In Figure 4.3 a schematic overview with the logical statements defining the modes is shown.

4.4 Vensim Modeling

4.4.1 Technical

Firstly, technical assumption have been for modeling the electrolyzer efficiency. According to commercial electrolyzer data available at the moment, the electrolyzer efficiency usually ranges between 65% and 70%, depending on the load applied relative to the nominal load. Since it is expected that the system efficiency for a PEM electrolyzer will improve as PEM becomes a more mature technology, the maximum efficiency is set to 75%. The following lookup table is used modeling the stack efficiency depending on the load applied, see Table 4.1.

Rel. stack load [-]	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
Efficiency [-]	0.65	0.66	0.67	0.68	0.69	0.70	0.71	0.73	0.75	0.75

Table 4.1: Lookup table for energy efficiency modeling of the electrolyzer stack in Vensim

4.4.2 Economic

To key economic parameter indicating the cost per generated quantity of energy, is the levelized cost of energy (LCOE) which is calculated by dividing the cumulative capital and operational costs by the average annual generated energy, see Equation 4.1:

$$LCOE = \frac{CAPEX/\alpha + OPEX}{E_t} \; [€/MWh] \tag{4.1}$$

where $CAPEX$ [€] is the capital expenditure, $OPEX$ [€/year] is the operational expenditure, α [years] the annuity factor and E_t [MWh] the total annually generated and distributed energy by the system. The annuity factor is a function of the real discount rate r [%] and the economic lifetime LT [years] of the technology considered:

$$\alpha = \frac{1-(1+r)^{-LT}}{r} \tag{4.2}$$

The cumulative economic revenue for hydrogen and electricity are defined in Equation 4.3 and 4.4, respectively. This cumulative revenues are the results from the SD software. The hydrogen sale price P_{H_2} [€/MWh] is fixed for this study, whereas the electricity price P_e [€/MWh] is the EPEX day-ahead spot price on hourly basis. $E_e(t)$ [MWh] and $E_{H_2}(t)$ [MWh] represent the electrical and hydrogen energy generated at time t, respectively.

$$R_e = \sum_{t=1}^{t_S} E_e(t) P_e(t) \tag{4.3}$$

$$R_{H_2} = \sum_{t=1}^{t_S} E_{H_2}(t) P_{H_2} \tag{4.4}$$

4.4.3 Performance indicators

Another performance indicator for the economic performance of the total system is the revenue factor (F_{rev}) as defined in this study, see Equation 4.6. This factor is a ratio between the average price of electricity sold to the market by the system divided by the average price of electricity over the full simulation period. This fraction indicates the change in revenue with caused by the mode of operation. This can be calculated by a comparison to the average electricity price over the period of analysis. The average price of electricity can be calculated by:

$$\overline{P_e} = \frac{R_e}{E_e} \; [€/MWh] \tag{4.5}$$

where R_e [€] is the total revenue of the electricity sold and E_e [MWh] the total electrical energy sold to the market after cable losses. The revenue factor F_{rev} is now calculated by:

$$F_{rev} = \left(1 - \frac{\overline{P_{e,sold}}}{\overline{P_e}}\right) * 100 \ [\%] \tag{4.6}$$

where R_e the cumulative revenue from electricity trading and $\bar{P_e}$ is the average price of electricity for the years of analysis. The revenue factor F_{rev} is expected to give positive values for the scenarios operating in the mode where electricity is sold to the market only in case the price of electricity is high (operation mode 3).

The pay-back periods for electrolyzer systems is often given in literature as an indicator for the profitability of a system and hence the pay-back period of the system is calculated, see Equation 4.7 [43]:

$$PBP = \frac{CAPEX}{R - OPEX} \tag{4.7}$$

where R [€] the total annual economic revenue by selling both electricity and hydrogen to the market. The pay-back period is a result of the net present value which is an indicator determined by the total investments (negative) and the revenue streams (positive), see Equation 4.8.

$$NPV = -CAPEX - OPEX * \alpha + R_{H_2} + R_e \tag{4.8}$$

where R_{H_2} [Mrd. €] is the annual economic revenue of hydrogen and R_e [Mrd. €] the annual economic revenue of electricity. All the above mentioned performance indicators are used to test the model for different scenarios, which will be explained and tested in Chapter 5.

Chapter 5

Results

This chapter will show the results of the different scenarios and operation modes as discussed in the previous chapter. It will display the performance of the electrolysis system and the total energy losses depending on the mode and input values.

5.1 Scenarios

5.1.1 Fixed parameters

For the cost modeling, the cost per component are assumed to be fixed in the first place based on the literature study in Chapter 3. An overview of these parameters are given in Table 5.1. The base values are used to test the model in the first place with the given scenarios. The values for electrolyzer investment is fixed at 700 €/kW. The stack balance of plant was estimated previously to be 40% of the total stack investment cost, resulting in base value of 470 €/kW. The total operational expenditure is estimated by multiplying the total capital investment by a factor R_{OC}. From literature and previous studies it turned out that for all components required for the wind farms, the OPEX is 2%. For the electrolyzer and gas infrastructure the OPEX is in the range of 2-4%. Accounting for unexpected operational costs, the base value for this ratio is set to 4% for the simulations. Vensim software is performing simulations by using a forward Euler time integration method with a time step of 1/8 hour, 0.125 h. As the global error is proportional to the time step size, the predicted error for a time step of 0.125 h is 1.6%. The System Dynamics Society stated that 1/8 is a reasonable time step length for SD modeling [15]. Furthermore, for the economic analysis the annuity is calculated by using Equation 4.2 based on the assumed real discount rate of 3% and lifetime of 30 years, the annuity is 20 years.

5.1.2 Testing

The WHS model is tested for the different operation modes as described in Section 4.3.2, 4.3.1 and 4.3.3. These operation modes are tested for three different electrolyzer capacities. Furthermore, for operation mode 3 the market optimization is tested for several European energy markets by elaborating two case studies in Section 5.3.3 and 5.3.2. This has been done with market data available over the period 1-1-2013 to 31-12-2016. The corresponding wind climate data for this duration has been retrieved from the database downloaded from the DOWA Wind Atlas. For each mode, several scenarios are created for the main parameters in the model, indexed from A-F: operation mode (A), installed wind capacity in GW (B), ratio stack wind capacity with a values ranging between 0 and 1 (C), distance to shore in km (D), water depth in m (E) and country of landing point (F). The ratio stack wind capacity C is a ratio representing the desired stack capacity divided by the installed wind farm capacity. The final electrolyzer stack capacity may differ due to capacity optimization within the WHS model. The country of landing point, F, is the country for which the electricity market will be analyzed.

The distance to shore for scenario 10-13 corresponds with the direct distance to the landing

Name	*Abbreviation*	*Low*	*Base*	*High*
Economic modeling parameters				
HVDC cable investment costs	I_C [€/km/kW]	-	1.1	2.3
Stack investment per kW	I_{ES} [€/kW]	500	700	1000
Stack balance of plant cost per kW (40 % of total stack investment cost)	$I_{ES,BOP}$ [€/kW]	330	470	600
Hydrogen sale price (fixed in time)	P_{H_2} [€/kgH_2]	3	4.5	6
Hydrogen sale price (fixed in time) based on LHV_{H_2} of 33.33 kWh/kgH_2	P_{H_2} [€/MWh]	90	135	180
Fixed WHS model parameter values				
System lifetime	LT [years]	-	30	-
Discount rate	r [%]	-	3	-
Annuity	α [years]	-	20	-
Ratio OPEX CAPEX	R_{OC} [%]	-	4	-
Total duration of simulation	t_S [years]	-	4.0	-
Time step simulation	Δt [hours]	-	0.125	-
Minimum level buffer	BL_{min} [-]	-	0.10	-
Maximum level buffer	BL_{max} [-]	-	0.95	-
Time of smoothing EPEX price	T_{avg} [hours]	-	96	-

Table 5.1: Overview of important parameters in the model

# scenario	A: operation mode	B: wind capacity	C: ratio wind stack	D: distance to shore	E: water depth	F: country
00	0	12	0.0	150	50	NL
01	1	12	0.2	150	50	NL
02	2	12	0.2	150	50	NL
03	3	12	0.2	150	50	NL
04	1	12	0.5	150	50	NL
05	2	12	0.5	150	50	NL
06	3	12	0.5	150	50	NL
07	1	12	0.8	150	50	NL
08	2	12	0.8	150	50	NL
09	3	12	0.8	150	50	NL
10	3	12	0.5	235	47	NL
11	3	12	0.5	276	47	DK
12	3	12	0.5	297	47	DE
13	3	12	0.5	439	47	NOR
14	3	20	0.5	109	26	NL
15	3	20	0.5	320	26	UK

Table 5.2: Scenario evolution for testing the WHS model

points in the specific countries The Netherlands (NL), Denmark (DK), Germany (DE) and Norway (NOR). Both a pipeline and electricity cable is connected to the landing point and it is assumed that the energy is distributed further from their. The results for these scenarios are elaborated in case 1, Ten Noorden van de Waddeneilanden. For scenarios 14-15, similar simulations are generated with connections to The Netherlands (NL) and United Kingdom (UK). For each singular scenario 10-15 it assumed that electrical energy is sold on the specific electricity market for the country of landing point. A small sensitivity analysis is done for the hydrogen sale price is varied for these scenarios, since the high uncertainty of hydrogen market price is dominant for the total revenue and thus dominant for the payback period. It is assumed that no variances are observed for this hydrogen price among the considered European countries, despite the divergent readiness for hydrogen.

5.2 System Performance

5.2.1 Technical analysis

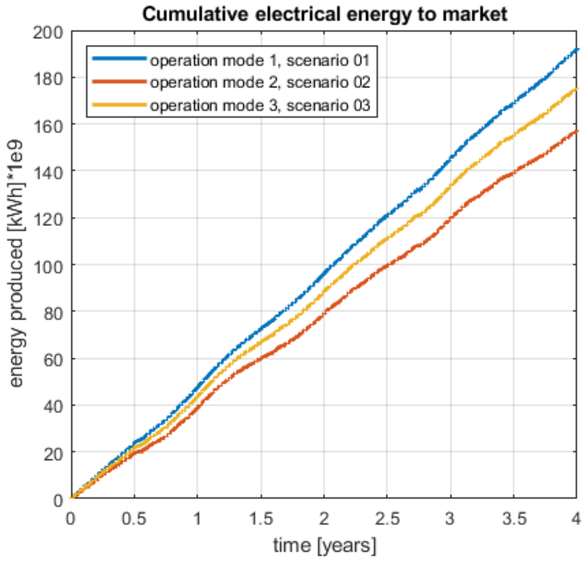
Before applying several scenarios to the WHS model, the general performance of the system is discussed. At first the load duration curves are plotted for the main input 'Wind energy supply' with the two system distribution functions 'Electrical power to market' and 'Power to hydrogen', see Figure 5.3. The latter one represents the electrical load to the electrolyzer. The 'Electrical power to market' is the power after assumed DC cable losses. The total electrical energy to market and the total hydrogen distributed to shore are displayed in Figure 5.1. It can clearly be noticed that for the first operation mode (scenario 1), producing only hydrogen at peak loads, the highest levels of electrical energy are observed whereas the production of hydrogen is most fluctuating due to seasonal effects in wind energy generation. The installed capacities are displayed in Table C.2, Appendix C. From the load duration curves in Figure 5.3 it is shown that for operation mode 1, the total power fed into the electrolyzer (Power to hydrogen) and the total power distributed to shore (Electrical power to market) by cables sums up to the total wind energy supply. As expected, operation mode 3 show more drops in power, due to the more dynamic loads to the electrolyzer. Operation mode 2 has the highest hydrogen production, but not all of the hours on full load, with an electrolyzer capacity of 4,880 MW for scenario 01-03. The difference in performance for the three operation modes is shown in Figure 1 for a week period from June 17 to June 24. As can be seen, the peak load operation mode maximizes the load to the electrolyzer whereas the base load operation mode maximizes the energy to market if the wind power is high enough. Operation mode 3 (top right) has clearly more start and stop actions for the electrolyzer, which may reduces the system lifetime.

5.2.2 Economic analysis

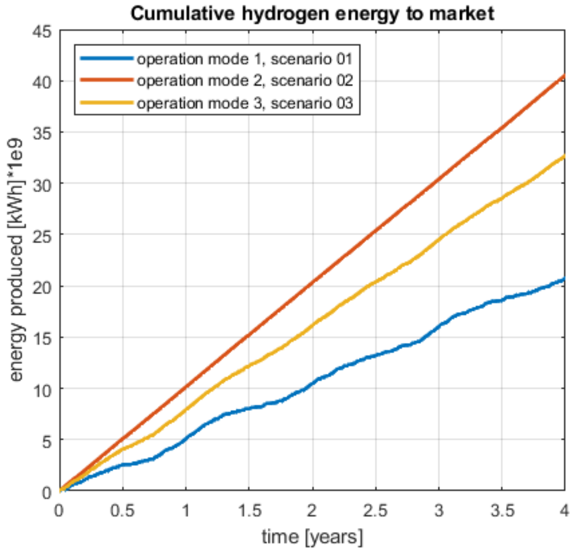
The results for testing the performance of different installed electrolyzer capacities for operation mode 3 are given in Figure 5.5 (results for operation mode 1 and 2, see Appendix C.2.2. The lowest PBP is observed for scenario 9, to be 14.9 years for a hydrogen price of 3 €/kg. In addition, the LCOE levels are calculated, see Figure 5.6. Obviously, higher values are obtained for larger hydrogen production levels with the maximum LCOE for scenario 8 with an LCOE of 74 €/MWh (79% more than base scenario 0).

In Figure 5.4 the results are shown for the net present value as defined in Equation 4.8. The results are showed for a hydrogen sale price of 4.5 €/kgH_2. The reference scenario 0 with only electricity submission shows that a payback period (PBP) of 24.4 years is achieved, as no added hydrogen revenue is gained. The other scenarios (1-3) with a wind stack ratio of 0.2 result in a PBP of 19.8, 16.3 and 17.5 years, respectively. The lowest PBP and thus the highest revenue is obtained for scenario 2 operating with a base load hydrogen production. This is a direct result of producing more hydrogen.

The performance of operation mode 3 is tested by calculating the revenue factor as defined in Equation 4.6. From the results (in Table C.3) it is observed that scenario 03, 06 and 09 have an revenue ratio of 0.9%, 3.9% and 10.1% respectively. These percentages are based on the average price of electricity over the simulation duration of 4 years with a mean electricity price



(a) Cumulative electrical energy to market for scenario 01, 02 and 03.



(b) Cumulative hydrogen energy to market for scenario 01, 02 and 03.

Figure 5.1: Production levels for simulation period 2013-2016, electricity market data for period 2013-2016

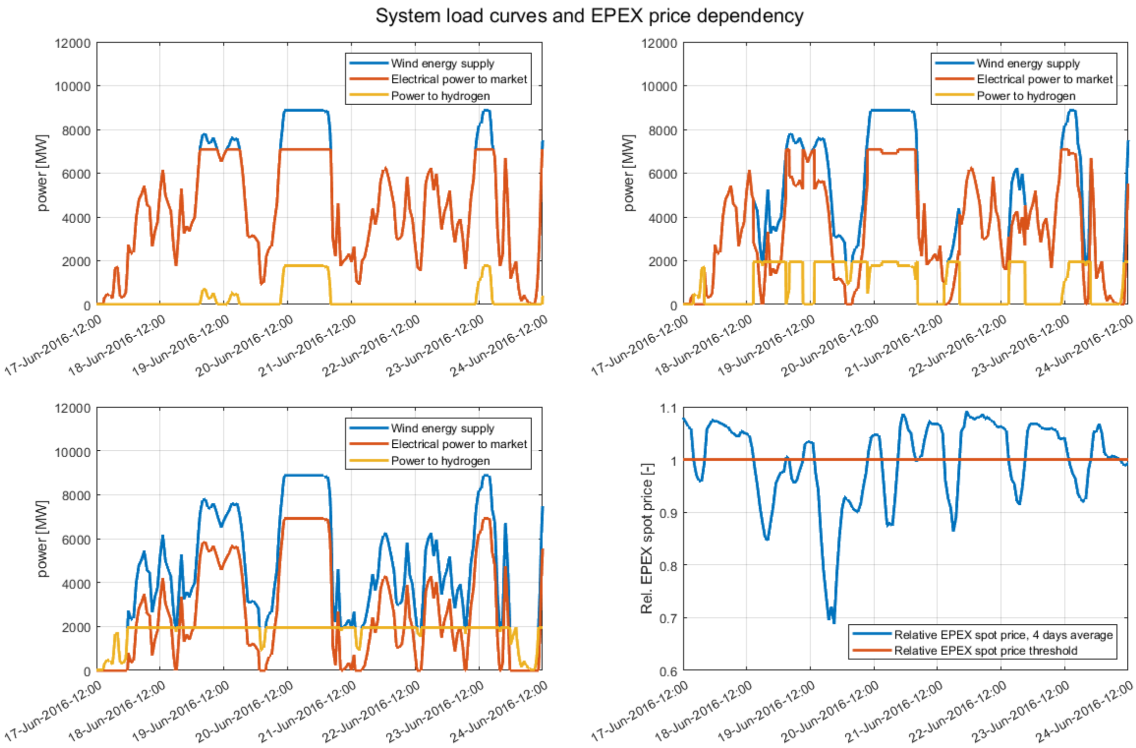
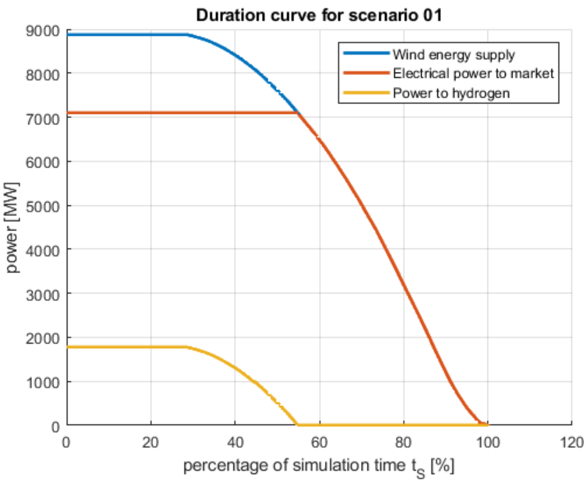
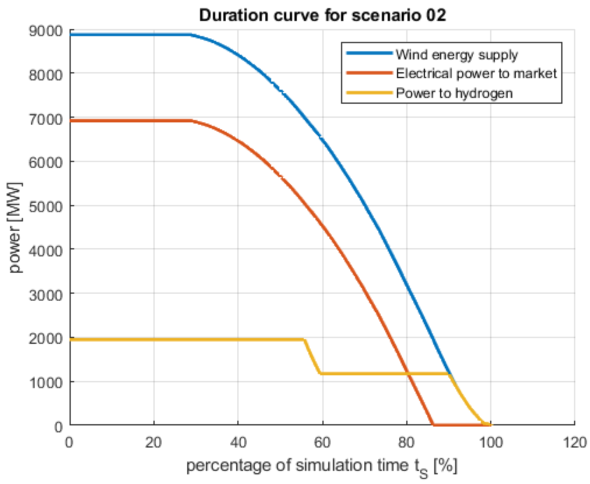


Figure 5.2: Load power of model functions for operation mode 1 (top left), operation mode 2 (bottom left), operation mode 3 (top right) and the relative 4-day smoothed EPEX price (bottom) for a duration of 7 days

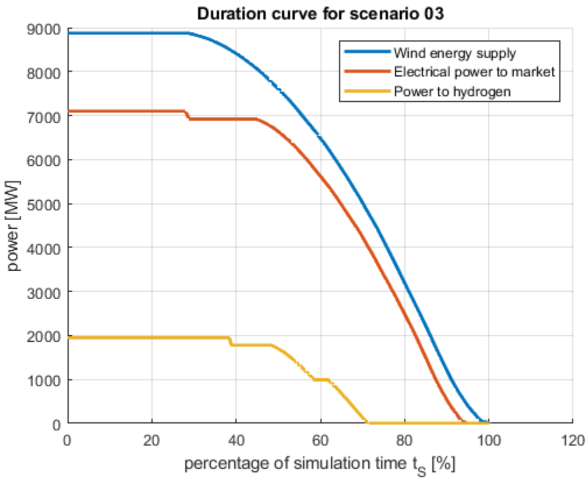
of 41.4 € /MWh for The Netherlands. It can be concluded that a larger stack capacity result in a higher electrical revenue on top of the increased hydrogen production levels.



(a) Scenario 01



(b) Scenario 02



(c) Scenario 03

Figure 5.3: Load duration curves for simulation period 2013-2016

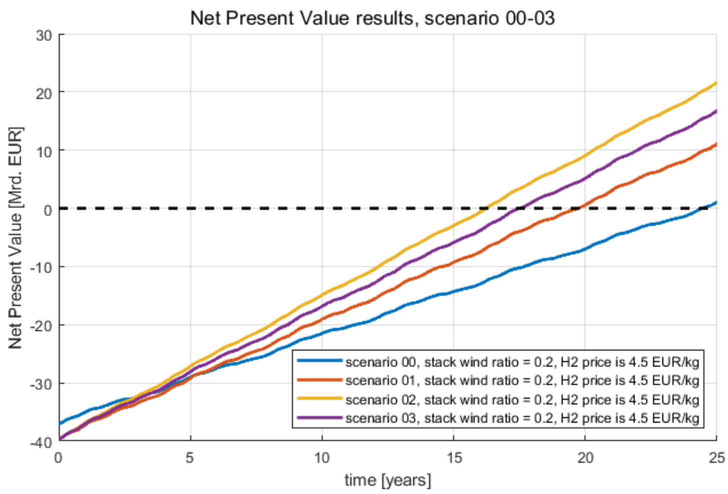


Figure 5.4: Net Present Value of the total system for scenario 00-03, simulated over a period of 25 years.

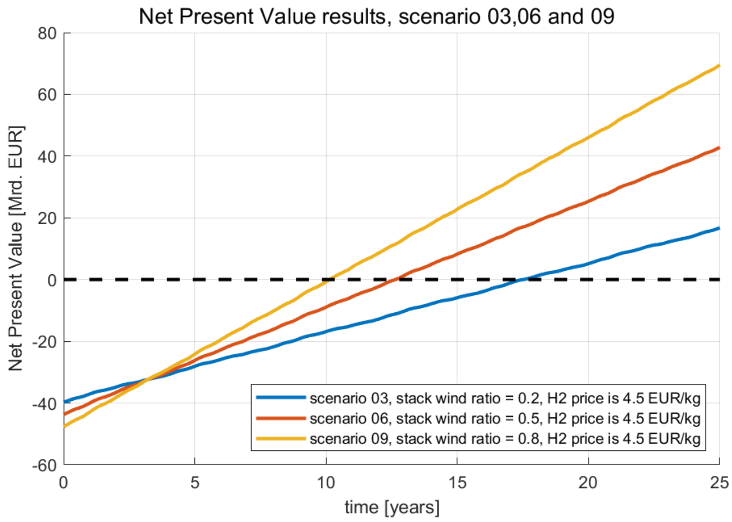


Figure 5.5: Net Present Value of the total system for scenario 03, 06 and 09, simulated over a period of 25 years.

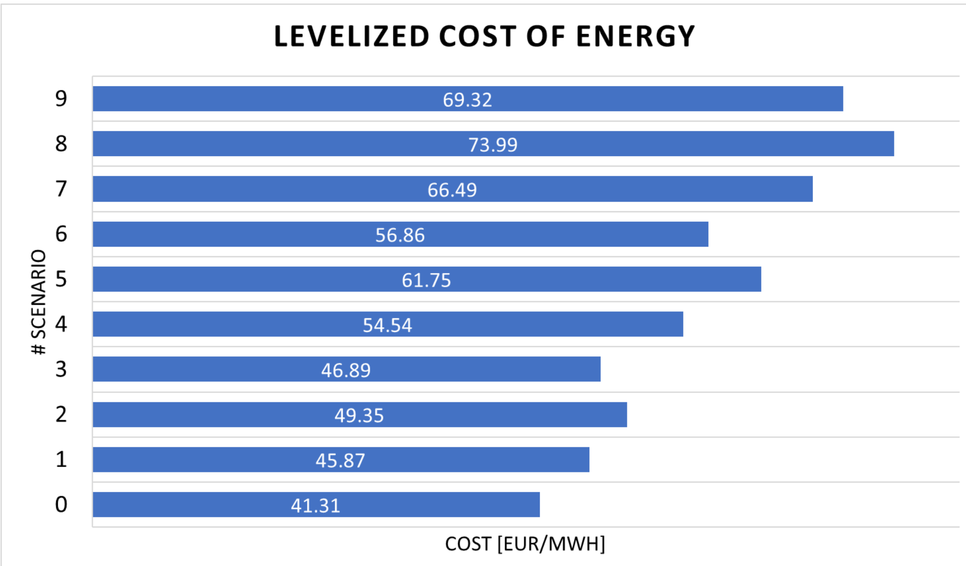


Figure 5.6: Levelized Cost Of Energy for scenario 00-09

5.3 Case Studies

5.3.1 Case study criteria

Two cases have been created to determine the business case for an offshore power-to-hydrogen system and to test the WHS model with accurate geographical data, such as water depths, geographical distances and wind climate. These two case are related to two energy hubs which in the centre of new proposed wind farms after 2030. Using the GIS model created by the NWSPH study in collaboration with Witteveen+Bos, two energy hubs are selected and the connections are made to onshore landing points. For both locations, the potential for expansion of wind farm capacity after 2030 is high. The following specifications are considered while evaluating the case studies:

- Site specific conditions: wind climate, mean water depth and distance to onshore landing point.

- Time of commissioning; possible learning curve implications.
- Discovering opportunities for re-using existing gas infrastructure.

The two cases as mentioned above are elaborated in the next two sections, Section 5.3.2 & 5.3.3. By connecting the hub to several countries, the performance of the market optimized operation mode (operation mode 3) can be tested. For both cases the hourly wind climate data for the selected hub location is used from the DOWA data set for the period 2013-2016 [42]. The hourly electricity market data (which is retrieved from the ENTSO-E and Nord Pool platform [18]) is synchronously simulated in the WHS model for the countries analyzed.

5.3.2 Case 1: Around Centrale Oestergronden

This case considers an energy hub northeast of the proposed wind farm site 'Ten Noorden van de Waddeneilanden' and north of the protected nature area 'Centrale Oestergronden'. This area is defined as a viable location for a multi-functional energy hub for multiple reasons. Firstly, the hub location is in the centre of proposed wind farms by the NSWPH study on the North Sea, taking into account spatial exclusions. Secondly, gas infrastructure is available with connections to Eemshaven. The province of Groningen together with industry companies in Eemshaven are collaborating to start with a hydrogen back bone to distribute the hydrogen onshore (HyGro, Hydrogen Hub in Northern Netherlands). Therefore it is assumed that the demand for green hydrogen is high for this region. The area location is near other European waters rather than The Netherlands, namely Germany, United Kingdom, Denmark and Norway. This gives the opportunity to distribute the generated wind energy to shore to multiple countries. This case study is tested by connecting the selected hub to the four aforementioned countries and applying the site specific conditions to the WHS model. Analyzing the electricity market of each individual country will give an insight in the economic performance of the energy hub for each country.

5.3.3 Case 2: Extension of IJmuiden Ver

This case analyzes an energy hub close to the wind farm area IJmuiden Ver (IJVER). This wind farm is divided in two phases which correspond to two locations, IJmuiden Ver Alpha and IJmuiden Ver Beta. The cumulative installed capacity will be 4 GW of wind power. It will be the first wind farm in the Netherlands connected with a HVDC grid connection system, which is favourable since a DC load is required for electrolysis. This wind farm site has been proposed being the optimal site to start a pilot energy island. A recent study supervised by BLIX Consultancy showed that for the IJmuiden Ver OWF it is economically and technically feasible to place an artificial island instead of constructing DC/AC converter platforms [44].

Secondly, their are multiple possibilities to re-use the existing gas infrastructure as the wind farm is surrounded by multiple platforms owned by the NAM and Neptune Energy. This have resulted in multiple research projects to investigate the feasibility of an artificial island including production of hydrogen. A good example is the IJVERGAS project which is a research pilot project which considers a multi-purpose island with several power-to-gas installations on the island. It is a feasibility study for the IJmuiden Ver area, by sizing the full energy system and determining the most suitable location within the area. The goal for this case study is to determine which site specific conditions are sensitive for the results of the techno-economic analysis.

5.3.4 Selecting hub locations

To test the WHS model for this specific location, a specific location for the energy hub is selected. The NSWPH study included wind farm areas which are proposed by the European North Sea countries, which is a baseline planned after 2030. It seems logical to select an energy hub which is within or close to these wind farms. The selected energy hub for case 1 is chosen from the

Specification	Value	Units	Notes
Wind farm capacity connected to hub	12	GW	
Sea water depth at hub location	47	m	
Distance to landing point in Eemshaven (NL)	235	km	
Distance to landing point in Conneforde (DE)	297	km	
Distance to landing point in Endrup (DK)	276	km	
Distance to landing point in Tonstad (NOR)	439	km	
Total CAPEX island, civil works	3,144	M€	Retrieved from NSWPH GIS model
Total CAPEX island, civil works and electrical components/connections	5,579	M€	Retrieved from NSWPH GIS model

Table 5.3: Overview of specific geographical and economic values for the hub in case 1

Specification	Value	Units	Notes
Wind farm capacity connected to hub	20	GW	
Sea water depth at hub location	26	m	
Distance to landing point in Beverwijk (NL)	109	km	
Distance to landing point in West Thurrock (UK)	320	km	
Total CAPEX export cables 10*2 GW, hub-NL	1,012	M€	2x506 M€, retrieved from NSWPH GIS model
Total CAPEX export cable 10*2 GW, hub-UK	1,868	M€	2x934 M€, retrieved from NSWPH GIS model
Total CAPEX island, civil works	2,723	M€	Retrieved from NSWPH GIS model
Total costs island, civil works and electrical components/connections	6,781	M€	Retrieved from NSWPH GIS model

Table 5.4: Overview of specific geographical and economic values for the hub in case 2

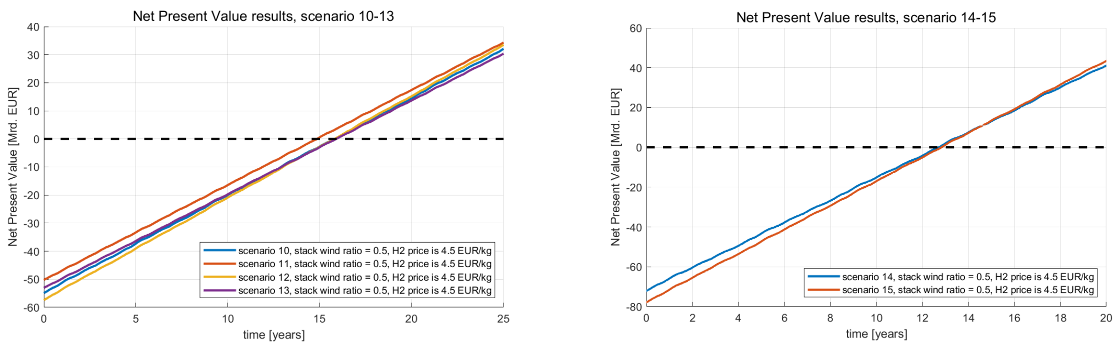
energy hubs drawn in the ArcGIS model, created by Witteveen+Bos (see Figure 5.9, green marker). For this case, connections are made to countries from the hub to the adjacent energy markets: The Netherlands, Germany, Denmark and Norway.

The hub location for case 2 in the IJmuiden Ver area is chosen north of the Ijmuiden Ver wind farm, see Figure 5.10. For further expansion of the installed offshore wind capacity, it is expected that the area north of IJmuiden Ver Alpha and Beta is suitable if further conflicting user functions are neglected or re-arranged [6]. Furthermore, from the IJVERGAS project it turned out that the gas infrastructure owned by NAM is suitable for large transportation of gas, whereas a 36 inch gas pipeline is connecting the NAM K15 platform with landing point locations in Den Helder and Eemshaven (see interviews with IntecSea and New Energy Coalition, Appendices A.2 and A.3). This gives opportunities to reduce costs in the future if these pipelines can be re-used for dedicated hydrogen transport. Obviously this needs a more thorough technical feasibility study before considering this, which is outside the scope of this study. For both cases, a set of 525kV HVDC cables and a hydrogen pipeline (blue lines) is connected to the onshore landing points.

5.3.5 Results

In this subsection the results for the scenarios related to the two cases are analyzed. As explained previously, connecting the hub to onshore landing points in neighbouring countries separately gives the opportunity to compare the performance for operation mode 3. The results of the net present value (NPV) for case 1 and case 2 are shown in Figure 5.7 for an assumed hydrogen spot price of 4.5 €/kgH_2. The initial investment at the start of the financial period is the capital expenditure and the operational cost over the calculated financial period (annuity). Apparently, for case 1 the PBP is in the range of 15 to 17 years for the four countries of landing point, whereas the PBP for case 2 is 12.5 years. This would imply that the location for case 2 is more suitable for an energy hub including hydrogen production.

The sensitivity for different hydrogen sale prices (3, 4.5 or 6 €/kgH_2) is analyzed for case 1 and to for a connection to The Netherlands (scenario 10 and 14). The results in Figure 5.8 show that a hydrogen sale price of 3 €/kg gives a payback period of 21 and 17 years, respectively. The payback period is still within the system lifetime, which makes it still profitable. In addition, calculating the mean electricity spot prices for which the electricity was sold to the market, the revenue factor as defined in 4.6 is calculated. For case 1, the revenue factor is in the range of 1.2% to 3.9% over the total simulation period (see Table C.3, Appendix C). For case 2 the revenue factor is 4.0% and 4.3% with an average electricity spot price of 41.4 €/MWh and 54.0 €/MWh by analyzing the electricity market of The Netherlands and United Kingdom respectively. This is a result of smart trading by only producing hydrogen in case the electricity price is below a predefined threshold (by definition operation mode 3, see Section 4.3.3). Case 1 shows better performances in terms of PBP due to shorter distances to shore and lower water depths with respect to case 2.



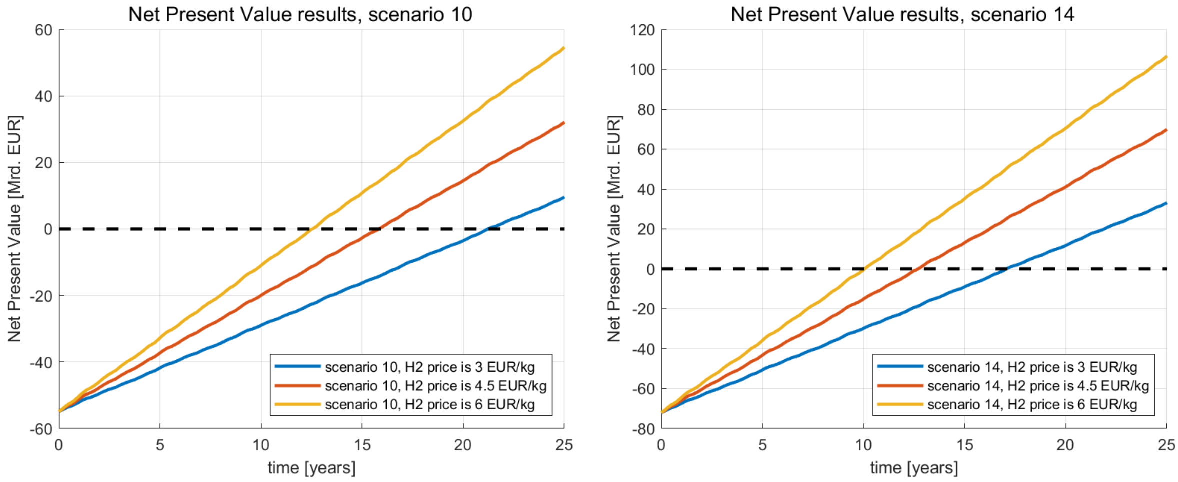
(a) Case 1, scenario 10-13, with markets NL, DK, DE and NOR respectively.

(b) Case 2, scenario 14-15, with markets NL and UK respectively.

Figure 5.7: NPV results for case 1 and case 2, base hydrogen price of 4.5 EUR/kgH_2

5.4 Discussion

It was observed that all proposed scenarios are profitable with pay back periods being lower than the assumed system life time. This implies that investors should be willing to start such large projects. However, it should be proofed whether the investment cost estimated in this study are accurate and reliable. This requires more situation specific feasibility studies, similar to current initiatives such as the North Sea Energy consortium. Recently, the North Sea Energy consortium performed an technical assessment to hydrogen production and transportation in the North Sea for four promising locations [45]. The technical and economic results from this study could be used optimize the WHS model and to verify the capital and operational costs.



(a) NPV results for case 1, scenario 10, country of landing point: NL

(b) NPV results for case 2, scenario 14, country of landing point: NL

Figure 5.8: NPV results for case 1 and case 2 corresponding to hydrogen prices of 3, 4.5 and 6 EUR/kgH_2

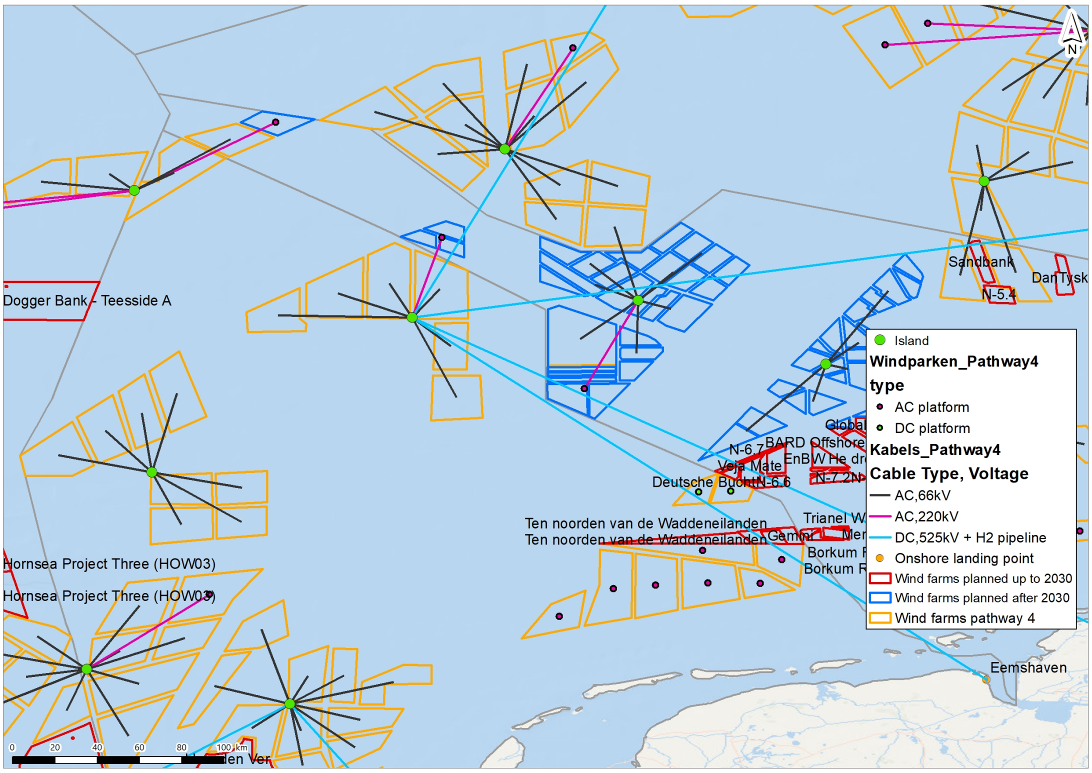


Figure 5.9: Around Centrale Oostergronden (case 1): GIS Map for offshore wind farms up to 2030 (red), planned after 2030 (blue) and new proposed wind farms (orange) in the North Sea. Reconstructed from the GIS model created and owned by Witteveen+Bos for the NSWPH project.

The WHS model could be improved by updating the values for investment electrolyzer costs with validated commercial data. It is recommended for the company Witteveen+Bos to set up more interviews with gas and electrolyzer companies to retrieve accurate data from currently running projects such as the PosHYdon project. Performing a techno-economic analysis for an

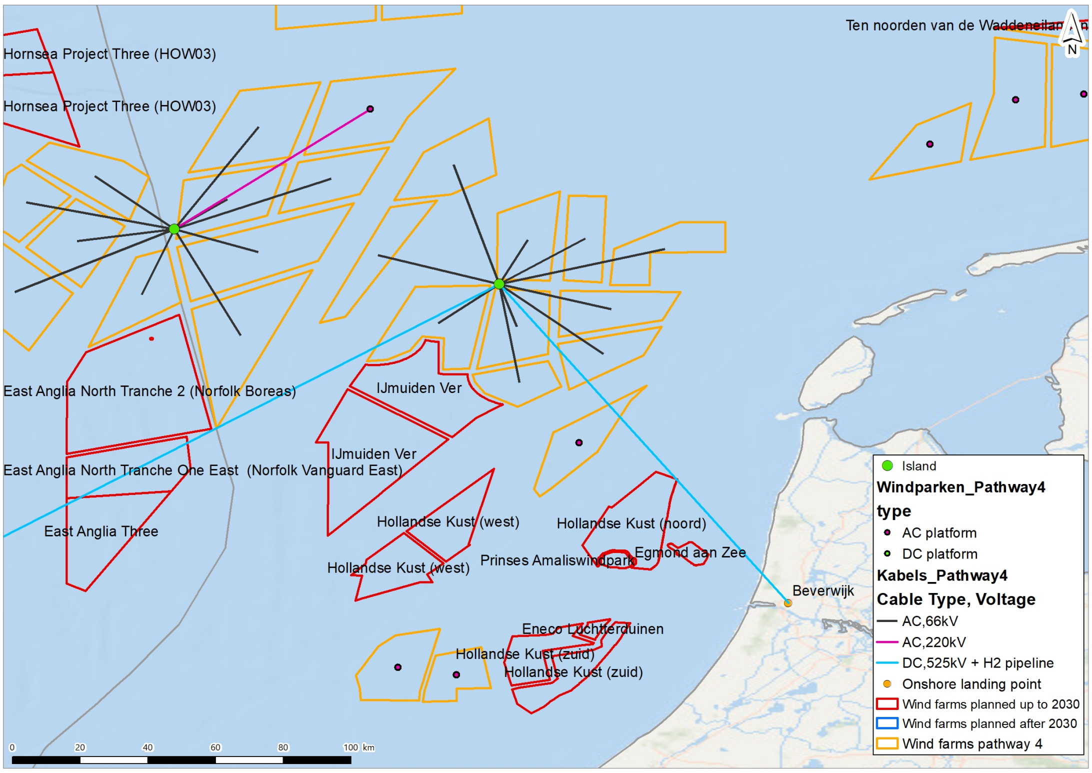


Figure 5.10: Extension of IJmuiden Ver (case 2): GIS Map for offshore wind farms up to 2030 (red) and new proposed wind farms (orange) in the North Sea. Reconstructed from the GIS model created and owned by Witteveen+Bos for the NSWPH project.

integration of multiple systems demands for reliable estimations. However, since the concept of an artificial island with integrated hydrogen production is not yet executed or tested, no system performance data is available to validate the output of the WHS model.

Secondly, opportunities which could benefit the business case for offshore hydrogen production should be explored. One proposed advancement in this study is re-using offshore gas platforms and gas infrastructure. It was assumed that using natural gas pipelines for hydrogen transport is feasible, but the induced cost reduction was not taken into account in this study. In terms of electricity market dependency, the impact on the electricity market by submitting large quantities of renewable energy to the grid is highly unsure. A more real-time market simulation with increased renewable power supplied to the grid is required, because this could possible affect the profitability of the market optimized operation mode analyzed in this study. Furthermore, the WHS model could be extended, testing the case where the hub is distributing energy to all surrounding countries. This could lower the connection capacity to each individual country and increase the revenue by providing energy on demand.

Chapter 6
Conclusion

Climate change policies has led an increased demand for offshore wind energy on the North Sea and an energy hub is proposed for distribution of the energy. This gives opportunities for a power-to-hydrogen system on an island, because it provides an additional revenue stream. A techno-economic study is performed to determine the business case for green hydrogen production by using offshore generated wind energy. The main research question was: "What is the optimal business case for an integrated power-to-hydrogen system for offshore wind energy hubs in the North Sea?"

The most relevant technical specifications and expenditure was analyzed for the five main system components: artificial island (energy hub), offshore wind farms, electrolysis process, gas infrastructure and electricity transmission. A System Dynamics model was created, named the Wind Hydrogen Simulation (WHS), to size the system components and to determine the revenue streams. As the extension of offshore wind energy on the North Sea will continue, energy hubs are expected after 2030. The integration of offshore wind energy into the onshore electricity system is becoming a barrier for further expansion. Production of green hydrogen on this energy hub has the potential to solve this problem and potentially improve the business case of offshore wind. In the sectors where electrification is difficult, like industry, an increase demand for green hydrogen is expected.

Adding hydrogen production to an energy hub decreases the transportation costs because pipelines are cheaper than cables. However, the electrolyzer stack is expensive so the total expenditure of the energy hub is increased. Due to energy losses in the electrolysis process, less energy is distributed to shore. Both these aspects increase the LCOE of offshore wind energy from 41 €/MWh to approximately 55-62 €/MWh for an energy hub with an electrolyzer stack capacity half of the installed wind capacity.

To test the performance, three operation modes: (1) peak load hydrogen production, (2) base load hydrogen production and (3) market optimized hydrogen production. These operation modes were tested for three different installed electrolyzer capacities with respect to the installed wind farm capacity, in either 20, 50 and 80 percent. The future hydrogen sale price is still uncertain, a likely range is between 3 €/kgH_2 (90 €/MWh) and 4.5 €/kg (135 €/MWh). If hydrogen is produced at times the electricity price is low and electricity is sold if the spot price is high, the electricity market revenues are 3.9% higher than the average electricity price of 41.4 €/MWh for an energy hub with the stack capacity half of the installed wind capacity. For an energy hub without hydrogen production the electricity market revenue is 1.2% lower than the average electricity price and this negative profile effect is expected to increase with expanded offshore wind capacity.

The results showed that despite the LCOE is increased by adding hydrogen production, the business case has been improved for both hydrogen sale prices of 3 and 4.5 €/kgH_2. The pay back period of the energy hub without hydrogen production is 24.4 years, whereas the energy hub with electrolyzer capacity half of the wind capacity has a payback period between 16 and 18 years depending on the operation mode (for a hydrogen sale price of 3 €/kgH_2). The best business case was obtained for the operation mode with a base load hydrogen production (operation mode 2). Comparing the 20, 50 and 80 percent electrolyzer capacity shows that 80 percent has the best overall business case with a payback period of 14 years for a hydrogen sale price of 3 €kgH_2. Finally, it can be concluded that this study showed that a power-to-hydrogen system on an energy hub for wind energy capacities of 12 and 20 GW is economically feasible after 2030.

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Appendix A
Company interviews

A.1 Interview Neptune Energy

Company: Neptune Energy, `https://www.neptuneenergy.com/`.
Names: Rene van der Meer, Jos van Ginniken, Menno Landsmeer.
Date: May 11, 2020.
Additional information: Jos van Ginneken: responsible for operations, compliance management. Rene van der Meer: employed since 2004. Many conventional projects. Project developments, non ENP, hydrogen production, CCS high on the agenda. Project manager of Q13 project. Interested in the system integration of hydrogen production and offshore wind. Involved in the PosHYdon project. This project from a technical point of view does not make sense. Goal is to learn how to handle hydrogen and consider the offshore infrastructure which is limited. Menno Landsmeer: since 2006, lead manager, projects and engineering. Involved in PosHYdon last year.

Are their possibilities for blue hydrogen production offshore? No, this hardly possible. SMR installation is hard to install offshore. Occupation/operation of the SMR will be to low, considering natural gas depletion is decreasing. Pipeline infrastructure is wijd vertakt. These are all connected to the main pipeline network which reaches shore at one location. Preferable to install a SMR onhore, mixed hydrogen and natural gas to shore in combination with SMR seems to be the first viable option. CO_2 transport per shipping is more easy than hydrogen. In addition we are looking to green certificates, how the green/blue hydrogen is valued. If you can sell your blue/green hydrogen to grey hydrogen consumers, that would benefit your business case. Discovering in the Poshydon project, market exploration. Neptune wants to be competitive with Russian high caloric gas, our goal is to reduce the CO2 footprint of our assets.

How does the mixing work, possible to separate it onshore? No separation unit available commercial, hyet hydrogen electrochemical compression to separate hydrogen and natural gas. For the Q13 not relevant because low hydrogen levels, H_2 concentrations are too low. That is the reason to look at SMR and CCS in the first place. How purified should the hydrogen be? Industry is still the biggest consumer; bulk of hydrogen has industry application. SMR is expected to be clean enough to insert in the 'hydrogen backbone'. Offshore produced hydrogen is nice but maybe not necessary to transport high quality green hydrogen in bulk volumes.

What could be a rule of thumb price per km or per diameter for offshore gas pipelines? Hard to give a number which fits to all projects because all project have different operating conditions, crosslinks with other infrastructure, most desirable wall thickness depending on operating pressure. For concrete coating for larger, long-distance pipelines even harder to determine. Also substations. Subsidy case asks for 100 MW electrolysis and in that case we will consider the full cost of the project. Than it is possible to estimate the cost of transportation from the single turbine to shore. Lengths, availability, price of steel, level of occupation ('bezettingsgraad') of shipping movements. We do not install 40 inch pipelines every year. Look at BBL and Nordstream project which have long distance transportation and the total project cost gives a good indication of cost per km per diameter.

What is the timeline for the Poshydon project? Hydrogen and fuel cell from RVO (JTI FCH) will provide subsidy to test the electrolyzer in Eemshaven which also investigates the requirements for the Q13 platform, 100 percent fund from EU. Containerized electrolyzers will be paid by this fund. It includes physical modification and installing the containers. Onshore test takes a year at least with a duration of one year for building the electrolyzers. End of 2022 expected start of hydrogen production. Container with high voltage 25kV to 10 kV converter and amplifier to make DC electricity. Also utility container with coolers and compression unit, this is the third container. All have an other destination after the pilot project. Challenge is to distribute oxygen and water input in a good manner. Desalination is usually not a big deal for us because desalination units usually exist on almost all platforms to provide drink water to the employee facilities.

A.2 Interview IntecSea

Company: IntecSea, `https://www.ingenieursbureau-in.nl/delft/intecsea`
Name: Ferry van der Linden
Date: May 14, 2020

What is the IJverGas project about?
The location for the artificial island is in the northern part of the Ijmuiden Ver area, because it is near the NAM K15 platform with the connected gas infrastructure. The hydrogen treatment should be done at the NAM location in Den Helder. For the project a new dedicated 16 km 16 inch pipeline is installed. Also a fit for purpose study will be done for the existing pipelines. Assumed that the pipeline is available and feasibility study in detail level in future. No pressurization units are added to the system, because 35 bar electrolyzer output should be sufficient. K15 lines, length with pressure distribution over the length the diameter is determined. Pressure drop over the total length is decreasing for increasing diameter. For an average flow of approx. 256,378 Nm3/hour and peak flow of 408,030 Nm3/hour for the 16 inch 16 km long pipeline. The pressure drop over the line is 5.5 bar. For average flow you have often above 20 m/s which is nominal for gas. The advantage of hydrogen over natural gas is the purity of the gas lacking hard molecules which could possible affect the wall quality (cracks).

What are the cost for hydrogen pipelines?
The cost for the dedicated hydrogen pipeline of 16 km length is estimated. The material cost of the pipeline does not take the largest part in the total construction cost. The cost division for the 16 inch, 16 km pipelines was material and coating (7.0 M€), sea defense and drilling (8.3M€), construction and installation cost (8.7 M€) and the near-shore riser (3.2 M€) which accumulates to a total estimated cost of 27.2 M€ . This is excluding management costs and contingency costs. 2 M€ for cleaning the pipelines, to get rid of damaging residues on the walls.

A.3 Interview New Energy Coalition

Company: New Energy Coalition, `https://www.newenergycoalition.org/`
Name: Malte Renz MSc
Date: May 18, 2020

What are the first considerations setting up a business case for offshore hydrogen production?
The main challenge I faced in hydrogen projects is how to determine the role of hydrogen being

applied to a certain sector. The sector such as industry or mobility affects the business case for hydrogen tremendously. In other words, the demand for hydrogen and the type of end-users determines the feasibility. This means that for your specific research, you should be clear in your technical and economic boundaries. The question is whether you start analyzing at the input of the electrolyzer or at the wind turbines input? Timescale depends as well, the operating life time of wind farms is 20 to 30 years. Considering the technical opportunities, the origin of your energy source should be clear. In your case it is clearly that wind energy is the only energy resource. In this respect, you may look at double fed induction generators (DFIG) for synchronous wind turbines. This technology opens new opportunities for hydrogen production, since no AC/DC and DC/AC converters/amplifiers are required. In this way one is able to avoid additional conversion losses, if the DC electricity is directly feeding the electrolyzer. This may be off topic for your research, but considering synchronous wind turbines is reasonable. At least it determines the power curve for your wind energy input.

To what detail should the electrolyzer be estimated in order to define the business case?
Some electrolyzers are more suitable than others. PEM has good performance with start-up times in order microseconds and wide variety of possible loads. At first, we made calculations on PEM technique in the IJverGas project, since the technique is expected to be most mature in the coming years.

Is it a valid assumption to assume linear dependency of electrolyzer efficiency between say 0.65 and 0.75 for ascending loads?
Yes, that is a good starting point for your case. If you get more into the technical performance of such a system, it may differ. Another component is the desalination unit which is definitely needed in the electrolysis process. However, it does not have a big impact on total CAPEX/OPEX. It also depends on the required purity for a certain PEM electrolysis cell. It should meet the water purity standard for a chosen PEM electrolyzer.

When do you expect to start with real commissioning of energy islands with hydrogen production?
This will not be within 2-3 years. Biggest headache for now is infrastructure should be ready as well if the island. Start of commissioning for Ijmuiden Ver wind farm will be in 2026 and the executors already decided to use 700 MW TenneT platforms. Infrastructure in north of Ijmuiden Ver area has many clusters which could be used with two major pipelines to Den Helder and Eemshaven. Therefore, it makes sense to locate the island in the north. There are constraints for pipelines in the south, with more smaller pipelines being less suitable for transportation of larger volumes of gas. In the north 36 inch subsea pipelines are situated. However, before realization of such islands, the transmission operators in the offshore environment should collaborate to make it possible. Because offshore is totally different arranged with responsibilities and properties, it brings a large group of stakeholders to the game.

Appendix B

WHS Vensim Model

B.1 Technical

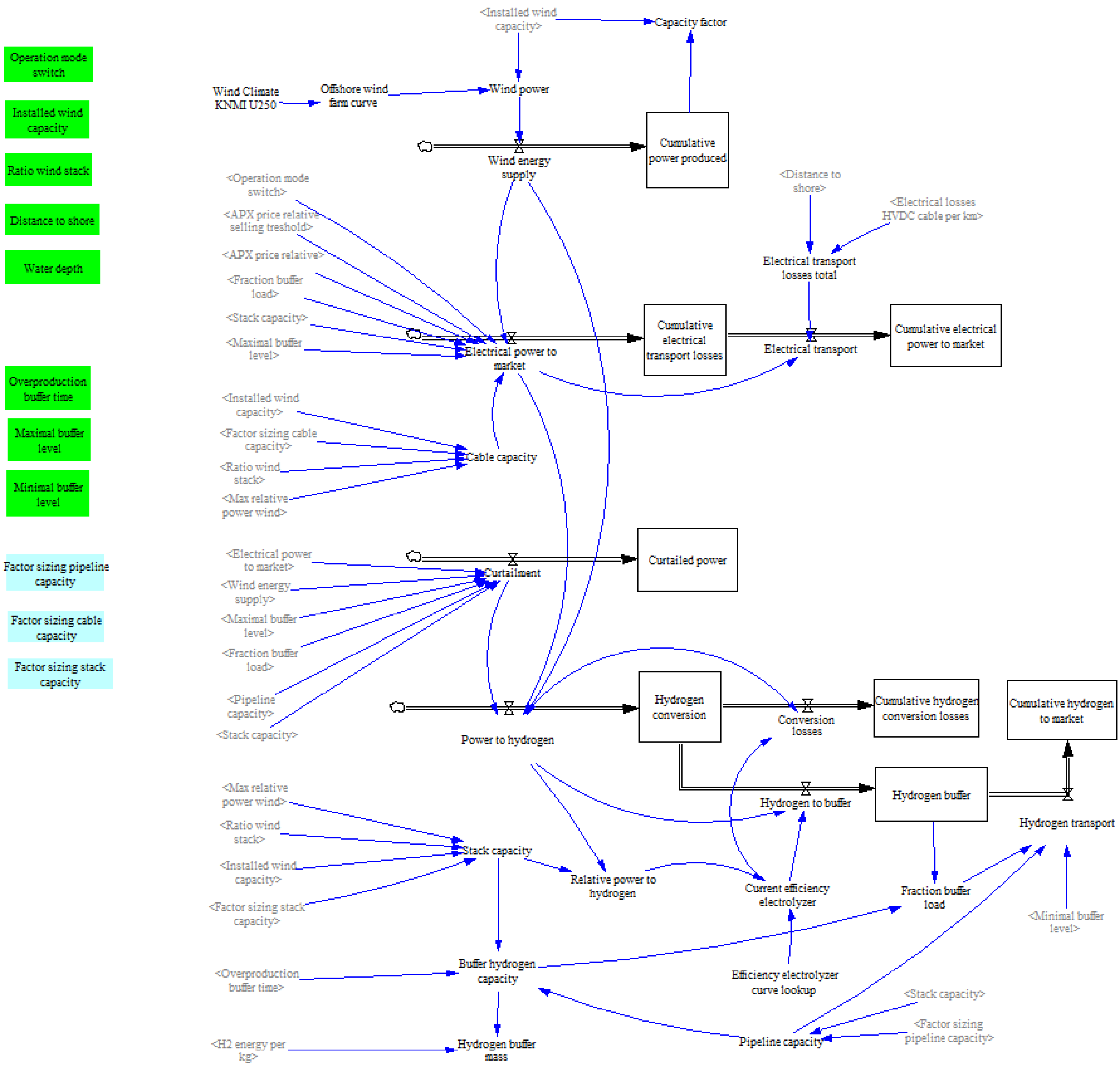

Figure B.1: Technical model as created in Vensim energy simulation software

B.2 Economic

In Figure B.2 the total cost breakdown of the expenditure calculation is given.

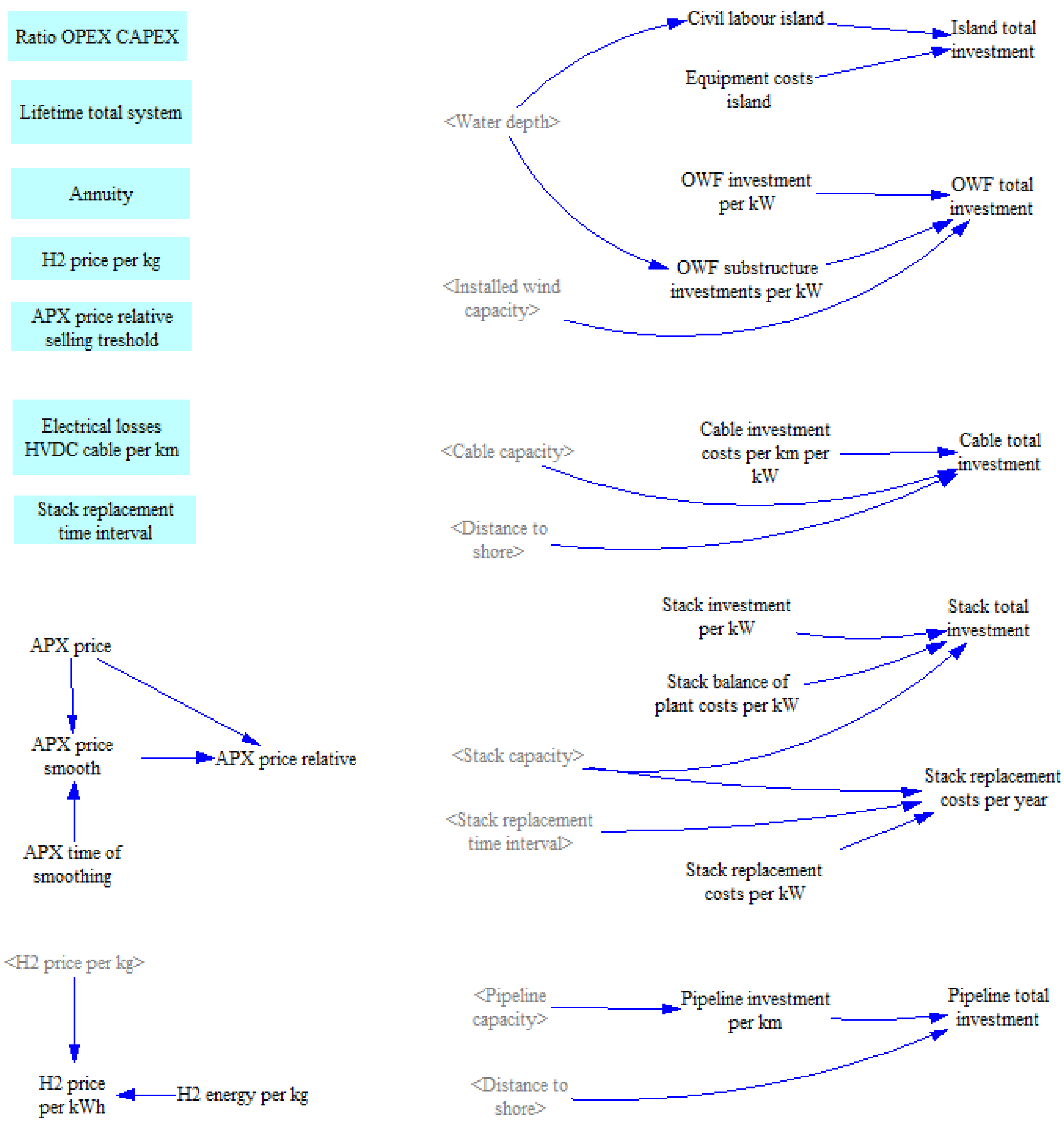

Figure B.2: Cost breakdown calculation in the WHS model to calculate the total expenditures.

Appendix C

Results

C.1 Variable information

Table C.1: Explanation of parameters used in the WHS model

Parameter name	*Explanation*	*Values*	*Units*
Operation mode switch	This index number describes indicates the mode 1,2 and 3 which determines whether the model is calculating values for peak load hydrogen production, base load hydrogen production or market optimized hydrogen production, respectively.	[1,2,3]	-
Installed wind capacity	Installed nominal wind farm capacity	[1-20]	GW
Ratio wind stack	Desired ratio or percentage for the electrolyzer capacity divided by the installed wind capacity	[0-1]	-
Distance to shore	Direct distance from centre point of the energy hub to the onshore landing point for both gas transport and electricity submission	[100-450]	km
Water depth	Sea water depth, head distance between sea water surface and sea bottom	[0-50]	m
Overproduction buffer time	Duration of loading the buffer at full capacity being SC-PC	[0-48]	h
Minimum buffer level	Lower boundary for the fraction of current energy stored in buffer divided by the total buffer energy capacity, used to avoid emptying the buffer entirely	0.10	-
Maximum buffer level	Upper boundary for the fraction of current energy stored in buffer divided by the total buffer energy capacity, used to avoid overloading the buffer	0.95	-
Factor sizing cable capacity	Factor multiplied to the cable capacity to increase or decrease the cable capacity manually	[0.5-1]	-
Factor sizing stack capacity	Factor multiplied to the stack capacity to increase or decrease the stack capacity manually	[0.5-1]	-
Factor sizing pipeline capacity	Factor multiplied to the pipeline capacity to increase or decrease the pipeline capacity manually	[0.5-1]	-

In Table C.1 the explanation of the main parameters used in the WHS simulation are given. The values correspond to the boundaries as used in this study.

C.2 Additional results

This section displays additional graphs and tables for the scenarios.

C.2.1 Tables with economic results

Table C.2: Final results for the installed capacities of the system as simulated for scenario 0-15

#scenario	WC $[GW]$	PC $[GW]$	SC $[GW]$	CC $[GW]$	CE_{H_2} $[TWh]$	CE_e $[TWh]$
0	12.0	0.00	0.00	8.87	0.00	220.49
1	12.0	1.40	1.95	7.10	20.78	192.33
2	12.0	1.40	1.95	7.10	40.41	157.65
3	12.0	1.40	1.95	7.10	32.58	175.87
4	12.0	2.93	4.88	4.43	65.32	132.34
5	12.0	2.93	4.88	4.43	97.55	77.04
6	12.0	2.93	4.88	4.43	83.48	106.11
7	12.0	4.68	7.80	1.77	120.18	57.11
8	12.0	4.68	7.80	1.77	144.34	14.96
9	12.0	4.68	7.80	1.77	133.13	36.90
10	12.0	2.93	4.88	4.43	83.48	106.01
11	12.0	2.93	4.88	4.43	83.30	105.60
12	12.0	2.93	4.88	4.43	82.68	106.75
13	12.0	2.93	4.88	4.43	79.67	109.95
14	20.0	4.88	8.13	7.39	138.73	176.60
15	20.0	4.88	8.13	7.39	142.41	171.12

with WC the total wind farm capacity, PC the pipeline capacity, SC the stack capacity, CC the cable capacity, CE_{H_2} the cumulative hydrogen energy to market and CE_e the cumulative electrical energy to market.

Table C.3: Final results for the electricity prices of the system as simulated for scenario 0-15

$\#scenario$	$\overline{P_e}$ $[€/MWh]$	$\overline{P_{e,sold}}$ $[€/MWh]$	$\overline{P_{e,notsold}}$ $[€/MWh]$	F_{rev} $[\%]$
0	41.44	40.96	0.00	−1.15
1	41.44	41.12	40.34	−0.78
2	41.44	40.88	41.26	−1.36
3	41.44	41.81	37.80	0.90
4	41.44	41.12	40.65	−0.77
5	41.44	40.56	41.27	−2.12
6	41.44	43.04	39.11	3.87
7	41.44	41.28	40.91	−0.38
8	41.44	40.16	41.02	−3.08
9	41.44	45.61	40.10	10.06
10	41.44	43.04	39.11	3.86
11	29.80	30.18	27.06	1.26
12	32.78	33.81	29.76	3.13
13	27.38	27.72	26.99	1.23
14	41.44	43.08	39.09	3.96
15	54.02	56.37	51.45	4.33

with $\overline{P_e}$ the mean day-ahead EPEX spot price, $\overline{P_{e,sold}}$ the mean day-ahead EPEX spot price for which the electricity was sold to the market, $\overline{P_{e,notsold}}$ the mean day-ahead EPEX spot price at the periods all electrical energy was loading the electrolyzer. The factor F_{rev} is calculated by using Equation 4.6. For all price values in Table C.3 it holds that the mean was taken over the simulation duration of 4 years, for 2013-2016.

C.2.2 NPV results

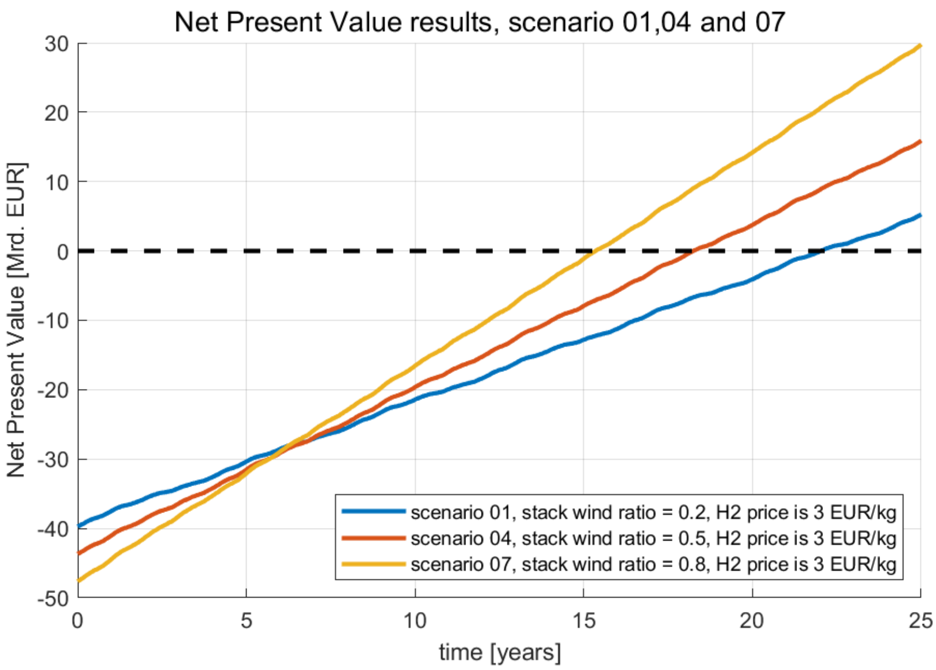

Figure C.1: NPV results for scenario 01, 04 and 07 (peak load hydrogen production) with a hydrogen price of 3 €/kgH_2

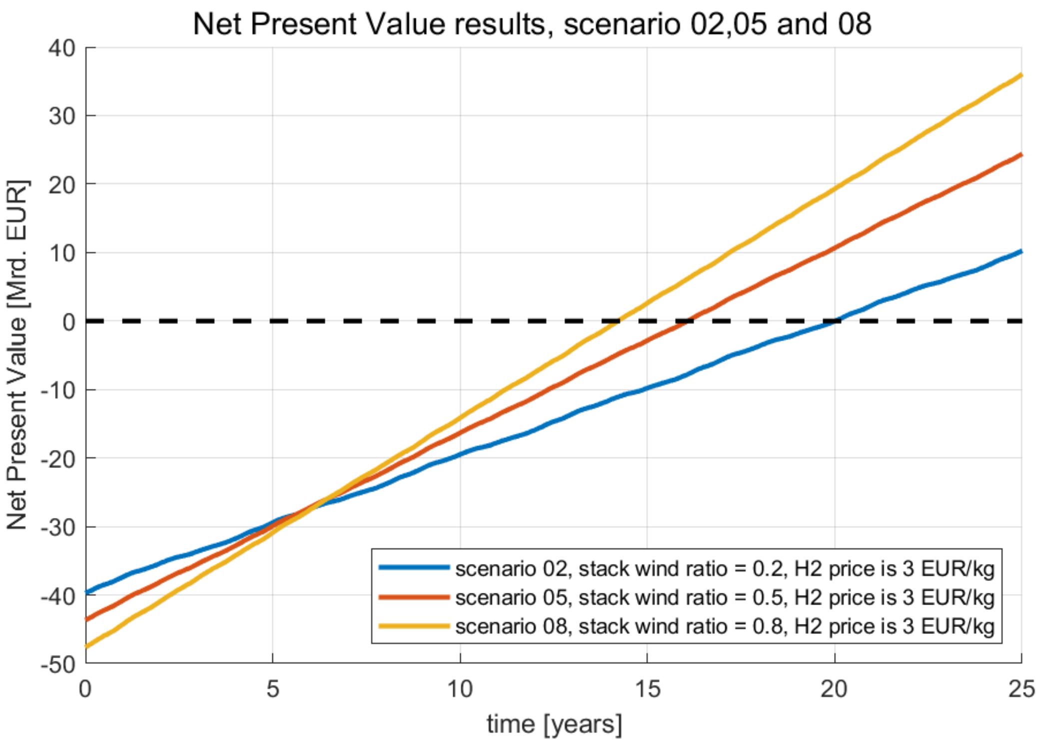

Figure C.2: NPV results for scenario 02, 05 and 08 (base load hydrogen production) with a hydrogen price of 3 €/kgH_2

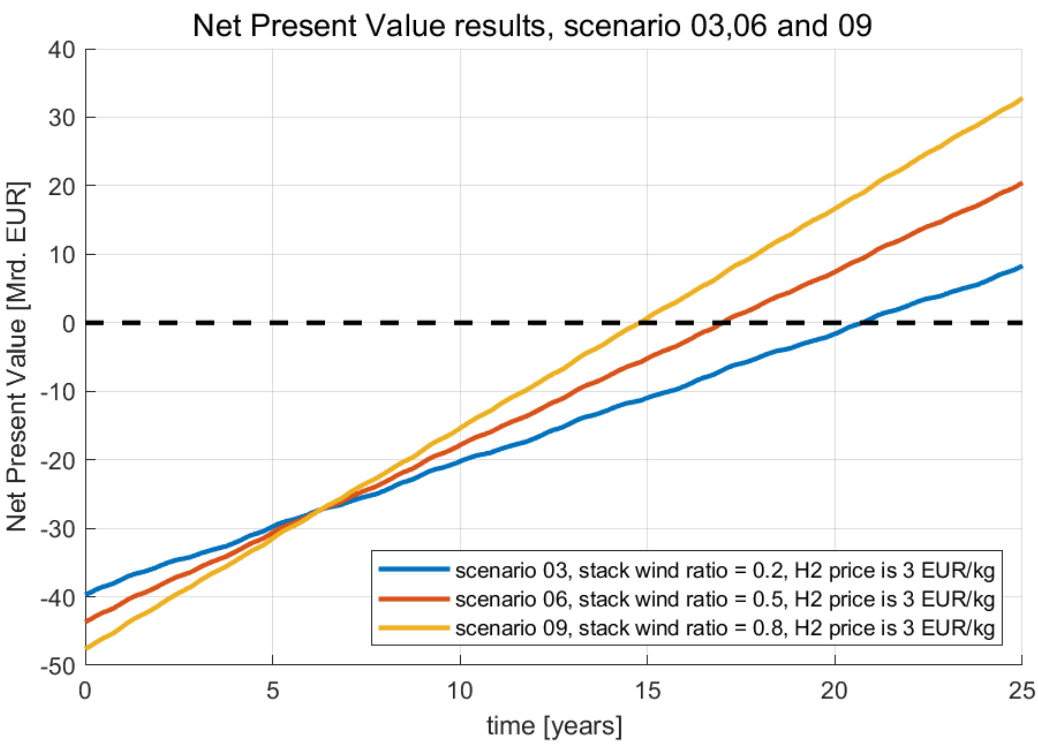

Figure C.3: NPV results for scenario 03, 06 and 09 (market optimized hydrogen production) with a hydrogen price of 3 €/kgH_2

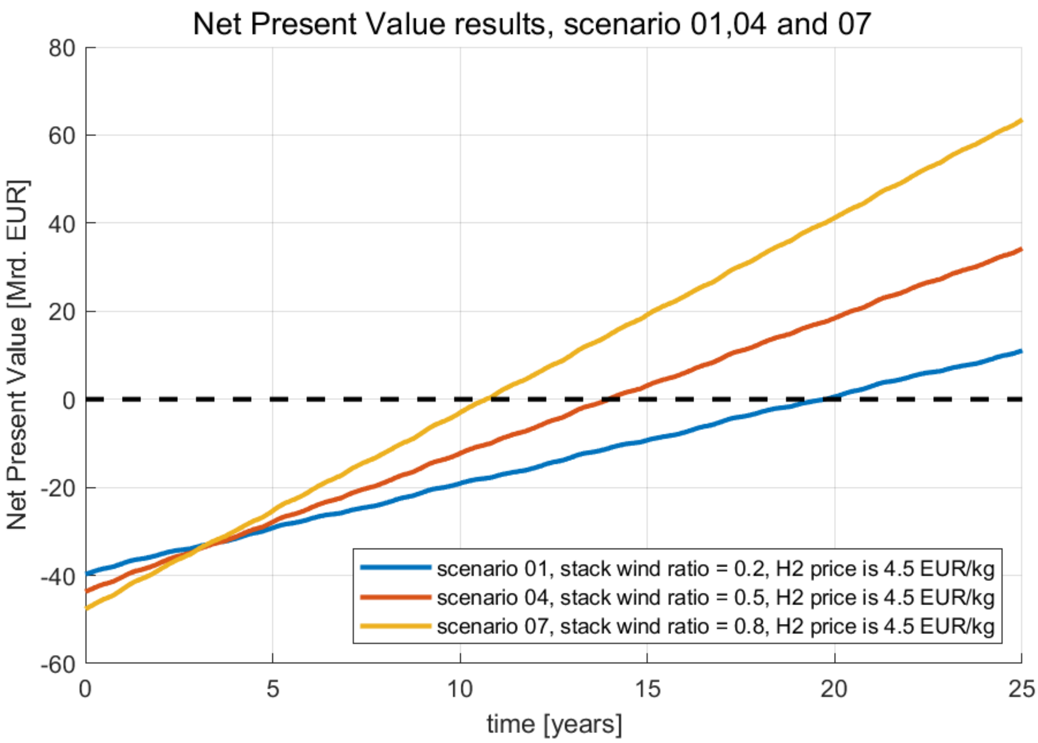

Figure C.4: NPV results for scenario 01, 04 and 07 (peak load hydrogen production) with a hydrogen price of 4.5 €/kgH_2

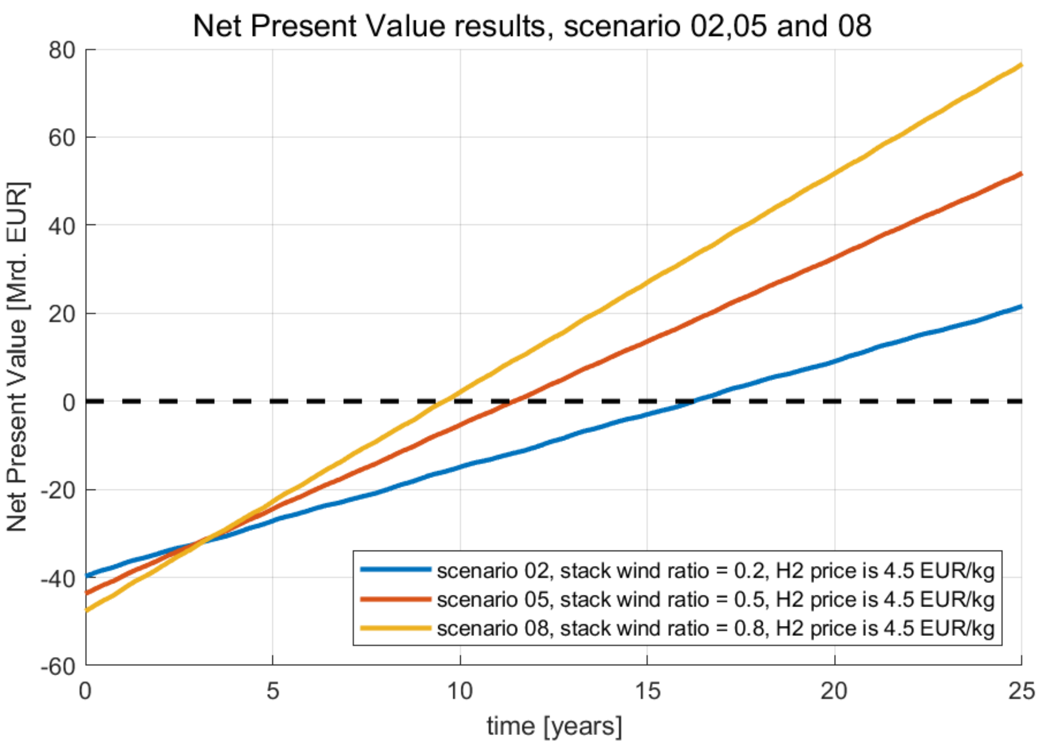

Figure C.5: NPV results for scenario 02, 05 and 08 (base load hydrogen production) with a hydrogen price of 4.5 €/kgH_2

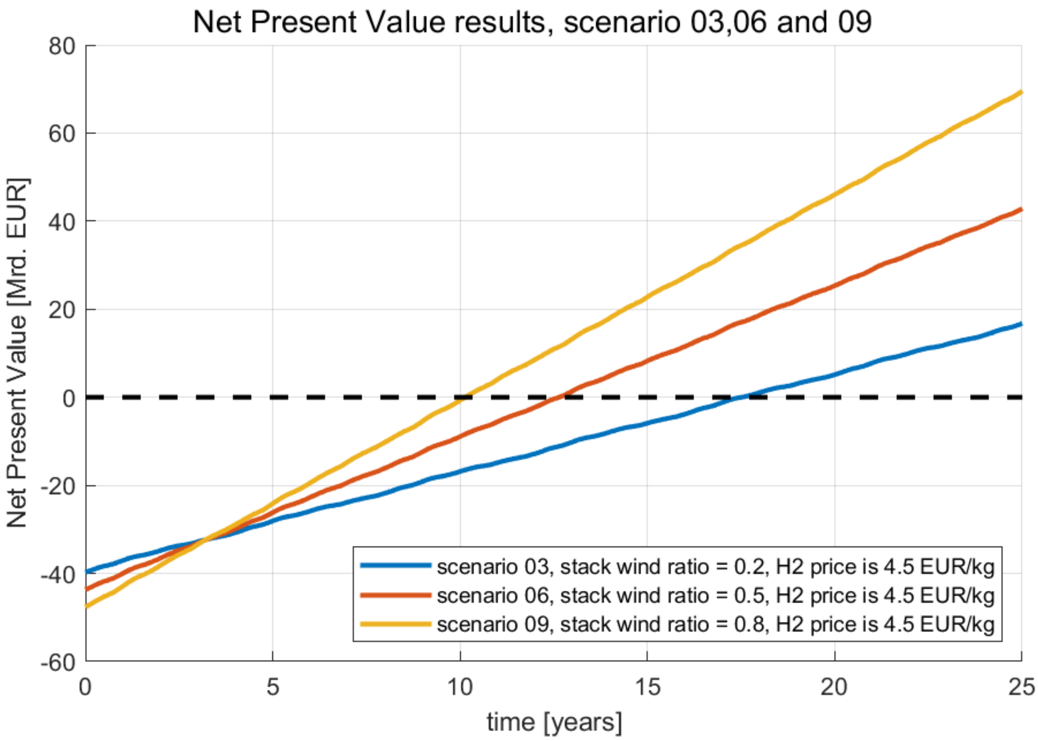

Figure C.6: NPV results for scenario 03, 06 and 09 (market optimized hydrogen production) with a hydrogen price of 4.5 €/kgH_2