IJVERGAS

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Contents

Summary

Wind generation on the North Sea is rapidly expanding. Offshore wind generation is expected to be a major source of energy for the future carbon-free energy system. The onset of this rapid growth is already visible. In the IJmuiden Ver area, 80 kilometres off the coast at Den Helder, a wind park expansion of 4 GW is planned by 2030, and possibly more, up to 10 GW, later. The 4 GW-expansion alone is four times the current Dutch offshore wind capacity.

To bring such vast amounts of wind energy to shore as electricity, extensive power conversion and transmission equipment is necessary. This would require considerable system expansion both offshore and onshore. Such grid reinforcements entail high financial and societal costs.

Hydrogen is an alternative energy carrier. Existing studies show a large potential for hydrogen for the North-Western European energy system, in which the Netherlands is embedded. Hydrogen is storable and can provide flexibility in an energy system with a high share of intermittent renewables. In addition, hydrogen is an important resource for industrial processes, transport and some say also for the build environment. Offshore wind power can be converted to hydrogen in power-to-gas (power-to-gas) facilities. This route is a promising alternative to bring vast amounts of wind power to shore and distribute it onshore.

The present study explores the opportunities and challenges of hydrogen generation on a multifunctional island in the IJmuiden Ver-area. It addresses primarily the energy dimension. The focus is techno-economical, however, also non-technical aspects are considered as the development of a multifunctional island requires a broad, systemic approach.

Multifunctional island concept

The proposed location for the multifunctional island lies in the IJmuiden Ver-area. This location has particular appeal due to its proximity to both the expanding IJmuiden Ver wind park and the existing natural gas pipeline infrastructure which could be reused for hydrogen. Given this location, the functions on the island could include a high voltage direct current (HVDC) power conversion station, a power-to-gas facility, a coast guard, facilities for operation and maintenance on offshore wind parks including an offshore base or marshalling yard, data centers, and services for fisheries. The construction of the island should be aligned with the “building with nature” principles, which should be further developed in collaboration with researchers and environmental organizations.

Energy conversion and transportation

This study focuses on the opportunities and challenges of hydrogen production on the multifunctional island. We assume that the island is dimensioned for a connected wind park of 2 GW. We distinguish four scenarios of wind energy conversion and transportation from the wind park to the shore. The four scenarios are designed to unravel specific effects of design choices of the island energy services. The scenarios differ by the degrees of freedom for converting and trading wind power:

- **Scenario 1 - Onshore hydrogen.** In this scenario we assume that wind power is transported as electricity to the shore. The HVDC power conversion station is on a

platform. Hydrogen is generated on shore. The net capacity of both the power-to-gas facility and the connecting power cable is 1.9 GW, assuming a net capacity of 95% for the
2 GW-wind farm. The net capacity takes into account losses from wake effect and collection system. The power-to-gas facility is also connected to the national electricity grid. The wind farm is connected through the power-to-gas facility, and has no direct connection with the onshore grid. All electricity from the wind farm is therefore converted to hydrogen. When wind generation is below 2 GW, the power-to-gas facility has the option to use additional electricity from the grid.

- **Scenario 2 – Island Hydrogen.** In this scenario both the HVDC and the power-to-gas facility are on a multifunctional island. Electricity is fully converted to hydrogen. There is no power cable from the island to shore. Hydrogen is transported to shore through a reused pipeline. The power-to-gas facility has a net capacity of 1.9 GW, but is not connected to the onshore grid, and can therefore only use electricity from the wind park.
- **Scenario 3 – Onshore Hybrid.** This is a hybrid scenario similar to Scenario 1. The single, but important difference between the two scenarios is the direct connection between the wind farm and the onshore grid (through the HVDC station on the island). The wind farm can thus sell electricity either to the power-to-gas facility or to the onshore grid. The power-to-gas facility can use electricity from the onshore grid when wind generation is below 2 GW.
- **Scenario 4 – Offshore Hybrid.** Also this is a hybrid scenario, one similar to Scenario 2. Also here the single but important difference between the two scenarios is the direct power connection between the wind farm (through the HVDC on the island) and the onshore grid. Scenario 4 has two versions. In the first version we assume a maximal cable capacity of 1.9 GW connecting the island with the onshore grid. In this version, the power-to-gas facility on the island has also a capacity of 1.9 GW. In the second version the capacities of the cable and power-to-gas facility are optimized. In both versions the wind farm can sell electricity either directly to the power-to-gas facility or to the onshore grid, within the limits of the cable capacity. Similarly, in both versions, the power-to-gas facility can buy electricity from both the wind park and the onshore grid, again within the limits of the cable capacity.

We assume that the IJmuiden Ver extension and all island functions are fully operational by 2030. This is an ambitious planning, however it is fitting with the fast pace of the energy transition, particularly on the North Sea.

Furthermore, we assume hydrogen onshoring at Den Helder and power onshoring in Beverwijk. Hydrogen is assumed to be transported between Den Helder and Beverwijk (back bone of Gasunie) through a to be constructed pipeline. Both are deemed realistic based on the criteria used in this study. However, these onshoring locations do not per se exclude other possibilities. The sensitivity analysis shows relatively small effects of the choice of onshoring on the results of this study.

Techno-economic analysis

The four scenarios are analysed to elucidate the effects of design choices on the business case of the multifunctional energy island. The techno-economic analysis follows the concept of Material and Energy Flow Analysis (MEFA), which combines material flow analysis (MFA), accounting for mass flows such as the required water for the electrolysis process and the hydrogen and oxygen output, with energy flow analysis (EFA). Following the MEFA approach allows to transparently account for all relevant flows of a complex process and linking them to their economic impact on the business case.

The energy system of the multifunctional island is embedded in a much larger national and international energy system. The techno-economic analysis takes this into account. In particular, it includes dedicated analyses of the electricity and hydrogen prices.

- **Electricity market prices.** Future electricity market prices are modelled using PowerFlex, an optimal dispatch model. PowerFlex simulates the dynamic operation of the electricity system via the price-driven dispatch of power plants, storage units and power-to-heat installations. The assets are dispatched to achieve lowest overall system costs, reflecting relevant constraints. Its output is an hourly electricity market price, which is used in the MEFA.
- **Hydrogen prices.** Future hydrogen prices are highly uncertain. The current market is opaque and its evolution difficult to forecast. For this analysis we therefore estimate the future hydrogen prices based on production costs plus margin. This approach still faces considerable uncertainties. To reflect these uncertainties, we use two prices: 1.5 euro per kg hydrogen and 6 euro per kg.

In addition, the techno-economic analysis also includes a detailed consideration of the wind park and island energy system components, in particular wind turbine characteristics, construction costs of the island, electrolysis, compression of hydrogen and reuse of pipeline infrastructure.

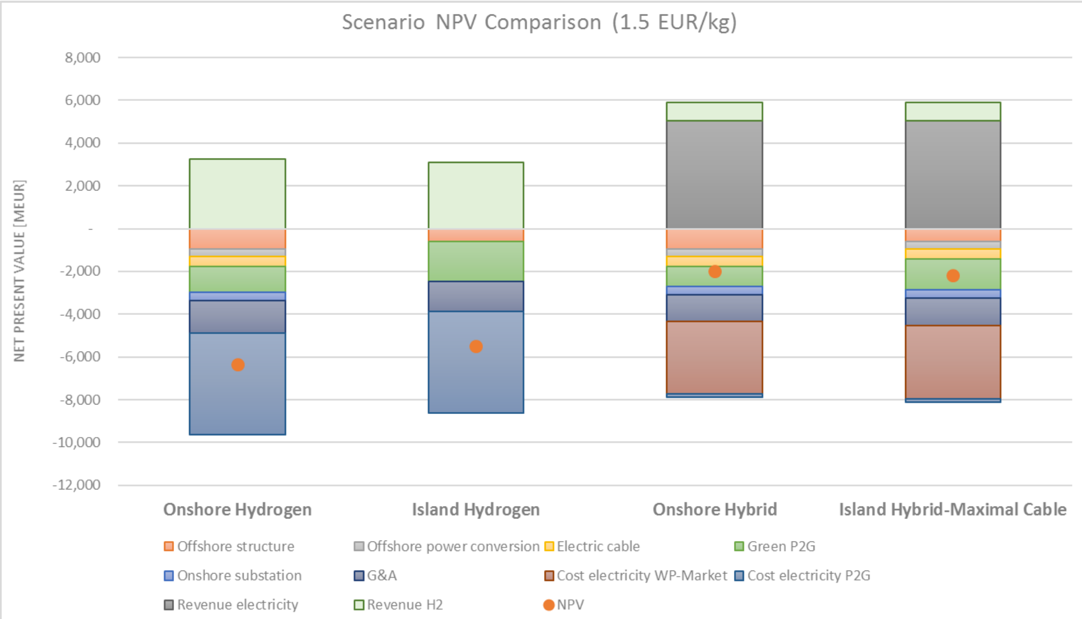
Results of the techno-economic analysis

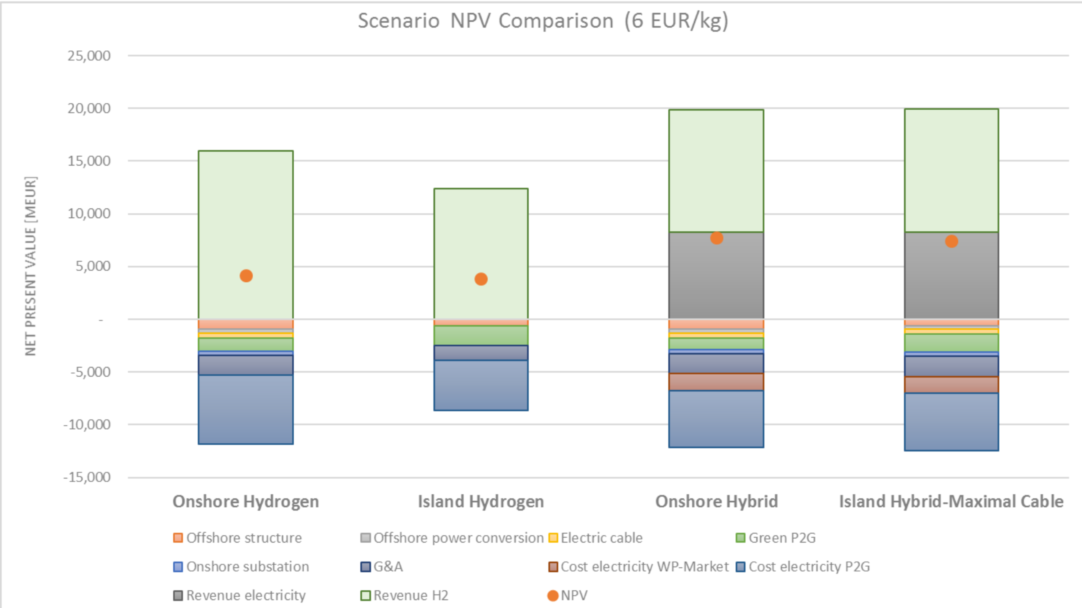
The techno-economic analysis shows particular sensitivity of the results to the future hydrogen price. The qualitative outcomes of the scenarios change completely depending on the two hydrogen price cases modelled. Scenario 4, the Island Hybrid scenario, is the most interesting scenario from the business case perspective of the multifunctional island. If the hydrogen price is low, 1.5 euro/kg, total net system revenues are maximized if all electricity is transported directly to shore, without conversion to hydrogen. For the high hydrogen price of 6 euro per kg, the conclusion is completely the opposite: net returns are maximized if all power is converted into hydrogen on the multifunctional island. In this case the cut-in electricity price for hydrogen production is almost 115 €/MWh, which results in a load factor of 97% and therefore a sound business case for offshore hydrogen production. Figure 1 shows a summary of the results. The break-even point between electricity sale and hydrogen conversion is found at 3.5 euro/kg to 4.5 euro/kg, depending on the electricity price assumptions. At higher prices, the techno-economic optimum entails the conversion of all wind power to hydrogen.

Apart from hydrogen prices, the outcomes are most sensitive to general financial parameters, particularly the cost of capital, the development of future electricity prices, technological developments in the field of offshore wind and conversion technology (electrolyser efficiency in particular), as well as the potential of multi-use of an island and a monetization of infrastructure externalities.

A multifunctional energy island, once it is established, reduces the overall costs of energy integration. This cost reduction boils down to a lower levelized costs of offshore hydrogen conversion by about 1 to 2 euro per kg compared to a situation with a separate substation and a dedicated P2G island. In this situation the system can make optimal use of the existing gas infrastructure (LOCAL pipeline) and reduces the transportation costs of energy. In various scenarios this means that there is a solid business case for creating such a multifunctional energy island.

Figure 1 - Summary of the results of the techno-economic analysis. The figure shows the results for four scenarios which differ in the share of wind energy converted to hydrogen and the location of hydrogen generation. Upper graph shows the results for a hydrogen price of 1.5 euro/kg, lower graph for 6 euro/kg





Non-technical aspects

The construction of a multifunctional island entails more facets than the purely techno-economical ones. In the further development of the island legal, policy, ecological, stakeholder and international aspects require dedicated attention. Moving forward requires broad collaboration amongst private stakeholders, as well as with the national, and possibly European governments. While the business case of this pilot project might not be entirely representative of future full-scale far-offshore islands, the current legal, permitting, market and systemic issues are not unique to the particular IJmuiden Ver area. Resolving these issues is an important step forward in the energy transition of the North Sea region.

Overall conclusion

This study is the first one to provide a broad analysis of factors determining the economics of hydrogen generation on an island in the North Sea, at a specific location. The envisaged location in the IJmuiden Ver area can harbour a pilot island which provides the opportunity to learn, innovate, and achieve a frontrunners position for future larger, further offshore developments of multifunctional islands.

This study shows that although from a purely techno-economical perspective the onshore option scores slightly better, the differences between the offshore and the onshore hydrogen production are relatively small. Future developments are likely to improve the business case of hydrogen production offshore on multifunctional islands. Increasing size and multifunctionality of offshore islands would allow for increasing benefits of the economies of scale. Further offshore locations can create larger benefits of energy transportation through (reused) pipelines. The scale of wind generation developments on the North Sea and the energy transition at large necessitates the development of such large-scale energy conversion and transmission approaches.

In practice, not only techno-economical, but broader societal factors are expected to play a major role in the design and construction of multifunctional islands. The realisation of a multifunctional island requires the support of various stakeholders including governments, private parties, and environmental organisations. A good stakeholder process from the early stages on is indispensable for the realisation of this and other multifunctional offshore islands.

1 Introduction

The energy transition is altering the energy system. Renewable energy, including wind energy, is expected to play a major role in achieving the Dutch climate goals. One of the issues with electricity generation from variable renewable sources is the variability of renewable generation and subsequent mismatch between supply and demand. This creates the necessity for a portfolio of flexibility options such as load following production, demand-response, storage, additional transport capacity and conversion. A good example of the latter is the conversion of electricity into other energy carriers such as hydrogen. These carriers can be of importance for to store energy, transport it, and decarbonise challenging sectors.

In this study we explore the opportunities and challenges of the production of hydrogen on an artificial island using electricity from nearby wind farms in the IJmuiden Ver area.

1.1 Background

The trend on the North Sea is a rapid growth of installed capacity of offshore wind, at increasing connection distances to onshore substations. For 2030 the Dutch offshore wind roadmap envisages 11.5 GW of offshore wind capacity; growing potentially to tens of GW in 2050. The early stage of this development becomes visible by the development of the IJmuiden Ver wind farm zone. They are foreseen to account for some 4 GW with wind farms starting to come online from 2027 onwards (see Figure 2). When completed this would equal four times[1] the current Dutch offshore wind capacity.

The large-scale deployment of offshore wind is one of the main opportunities to decarbonise our energy system. To bring such vast amounts of renewable electricity to shore in the conventional way (i.e. in the form of electrons) massive electric power conversion equipment (and the accompanying support structures) are required. The need for such additional electric capacity is not just limited to the offshore areas, but also implies onshore electric grid reinforcements at high financial and societal costs.

According to a study by PBL (2018) strong offshore wind deployment is thwarted by the lack of new landing points, and by grid congestion due to the sheer amount of power brought to shore in periods of high wind. These may already become serious issues around or before 2030. In Germany grid congestion has already led to high levels of curtailment of wind energy[2], and subsequent high costs. With future installed capacity on the Dutch North Sea increasing to potentially 60 GW of offshore wind in 2050 congestion and space for landing points are an even a more serious challenge.

The conversion of wind electricity to hydrogen could alleviate grid congestion and reduce curtailment of wind. It also could offer a more stable offtake for offshore wind electricity with a positive impact on the stability of the electricity market (i.e. avoiding negative electricity prices). For a sound business case of this concept a hydrogen market with a market price at or above the production price are required. This is financially a *conditio sine qua non*. Currently interest in hydrogen is gaining more and more momentum and so has the notion that large-scale application of hydrogen from renewable sources may become a key building block in the energy system.

1 At the time of writing the Borssele wind farm is not yet operational.

2 Germany's Maxed-Out Grid Is Causing Trouble Across Europe

Figure 2 - Dutch Offshore wind farm zones. The IJmuiden Ver area is highlighted

Source: (RVO, n.d.).

In recent studies several concepts are suggested to produce hydrogen offshore (North Sea Energy, 2019a), (North Sea Energy, 2019b), (Jepma, et al., 2018), (Pondera Consult; Arcadis, 2018b), (SER, 2018) (North Sea Energy, 2020d)These studies consider various offshore locations for conversion of wind power to hydrogen. Locations include both existing (e.g. oil & gas) platforms and new platform structures and/or energy islands. For platforms, an important limiting factor is the space available to reach sufficient economies of scale. The North Sea Energy programme recently concluded that it is more likely that offshore conversion for power to hydrogen in the GW range are more likely to be place on energy islands (North Sea Energy, 2020c).

Various analyses have been developed during the last few years with regard to the offshore construction of energy islands[3] (North Sea Wind Power Hub, 2019b), (Witteveen+Bos, ECN part of TNO, 2019), (North Sea Wind Power Hub, 2019a), (DNV GL, 2018), (North Sea Energy, 2020c). These studies generally agree on the large potential role for hydrogen in North-Western Europe. They also show that conversion of power to hydrogen offshore is technically feasible and that economic feasibility is nearby, both offshore and onshore. The tipping point for economic attractiveness of offshore versus onshore conversion depends on several factors, including the installed wind and electrolyser capacities, distance to shore, operational mode and costs (efficiency and electricity prices), market prices (of both electricity and hydrogen) and installation costs (primarily of the electrolyser).

DNV GL (2018) studied the concept of offshore power to hydrogen for the IJmuiden Ver area and concluded that power to hydrogen did not result in an improvement of the net present value of the value chain under the specific assumptions and timeframe studied. The North Sea Energy programme on the other hand concluded that 'under the assumption that green hydrogen has a significant role to play in our future energy system the Net Present Value results indicate a small preference for offshore production of hydrogen on energy islands over onshore production. In general, we observed that the major cost trends are favourable for the mid-sized island scenarios (2, 5 GW of connected wind capacity), which is in accordance with studies of the North Sea Wind Power Hub' (North Sea Energy, 2020c).

In both the North Sea Wind Power Hub (2019b) and the North Sea Energy (2020c) studies that focused on the potential of energy islands, the location of such islands was not clearly set. This has a large impact on the assumptions and outcomes of the economic feasibility of an energy island. A next step is needed. A location-specific and detailed techno-economic feasibility assessment is required to verify these earlier outcomes and progress the concept of multifunctional energy islands further. This study therefore specifically focuses on the potential of a multifunctional island near the IJmuiden Ver offshore wind farm area currently under development on the Dutch continental shelf.

1.2 Objective and scope of this study

The objective of this study is to explore the opportunities and challenges of the production of hydrogen on a multifunctional offshore island in the IJmuiden Ver area. We compare the economic returns of offshore versus onshore hydrogen generation, using quantitative modelling and scenario analysis. Recognising that economic costs will not be the only criteria in assessing the feasibility of a multifunctional island in practice, we also consider non-technical aspects such as stakeholder involvement and legal, ecological, and policy issues.

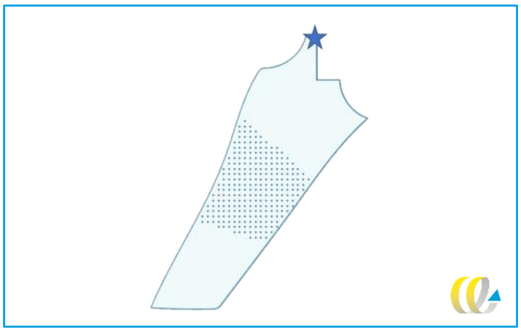
The core idea of the envisaged multifunctional island is the combination of different services. These services can range from energy-related to industrial, marine, and tourism activities, and include ecological services. In this study we focus on the energy activities: hosting offshore wind collection and AC/DC conversion and a power-to-gas facility that produces hydrogen using wind power.

The island in this study is assumed to be located on the Dutch continental shelf somewhat north of the area designated for the construction of the IJmuiden Ver wind farm, some 80 km to the west of Den Helder (see Figure 3). In this area currently 4 GW of offshore wind is in development, as a part of a total goal of 11.5 GW by 2030. According to the planning of the transmission system operator TenneT, the various offshore wind farms will be connected to

[3] Offshore island refers to islands in the open sea or ocean, constructed at water depths beyond 10 or 15 metres.

the onshore electricity grid using two HVDC-connections with 2 GW HVDC-substations each placed on jacket foundations. In this study, we assume a further 2 GW extension of IJmuiden Ver wind area to be operational by 2030. This creates an opportunity to the north of IJmuiden Ver to place energy services equipment on an artificial island and bring the produced wind energy to shore as electrons, as hydrogen or as both.

Figure 3 – Selected location (star) for the multifunctional island in the IJmuiden Ver wind farm area



1.3 Reading guide

This report contains the following chapters. This Chapter 1 is the introductory chapter. Chapter 2 discusses the technical design and construction of a multifunctional island. Chapter 3 provides a description of the potential island functions and described the four energy conversion scenarios. These two chapters form the basis for the techno-economic analysis. The methodology of this analysis is described in Chapter 4. The results are discussed in Chapter 5. Chapter 6 addresses non techno-economic aspects including legal, environmental, and stakeholder issues, that could be of importance for the the deployment of the island concept. Chapter 7 concludes this report. Technical details can be found in the appendices.

2 Island Design and Construction

This chapter describes the technical design and construction considerations for an offshore island in the North Sea. An offshore island is an island constructed in the deeper waters, at depths of more than 10 to 15 metres. The design and construction of such an island depends on the requirements of the use functions on the island and the environmental conditions in which the island is constructed and operated. This chapter describes the technical design and construction possibilities.

2.1 Background

The construction of artificial islands has been considered before, both for the IJmuiden Ver area and more general. This paragraph gives an overview of the relevant existing knowledge.

2.1.1 Artificial island in the IJmuiden Ver area

As described in Chapter 1, several parties have considered energy islands in the North Sea, in particular for new wind concession areas located further from shore. For the wind concession area at IJmuiden Ver an offshore island has been considered for an HVDC-station required to transport the generated wind electricity to the shore. The ministry of Economic Affaires & Climate Policy has contracted a study to analyse the different grid connection alternatives for IJmuiden Ver. Blix has performed this study in which several alternatives for grid connection have been evaluated (BLIX Consultancy, 2018). The study concluded that the connection via HVDC is preferred over an HVAC connection, among others because of lower levelized cost of energy (LCoE) for HVDC. A scenario for two times 2 GW HVDC-islands has a lower LCoE than for two times 2 GW HVDC-platforms in the case of IJmuiden Ver. The two times 2 GW HVDC islands have operational advantages over the platform option. For the first concession of IJmuiden Ver (4 GW) the ministry has chosen for HVDC platforms. The choice was motivated by planning considerations. The timely construction of the offshore islands was considered to pose a fair risk since the islands may not be operational by 2030, the defined timing for the operation of 4 GW wind at IJmuiden Ver.

The North Sea Agreement leaves room to enlarge the presently assigned area for IJmuiden Ver to the north to create space for an additional 8 to 10 GW of offshore wind. No studies have been performed on the gird connection of this area or on a power-to-gas (P2G) alternative. A realistic scenario may be that a combined solution is found in which part of the offshore energy is used to generate hydrogen and part of the offshore energy is connected via an HVDC-cable to the onshore grid.

2.1.2 Offshore islands

Islands or land reclamations have been constructed all over the world to enlarge land area for ports, industry, residential development, and recreation. In general sand is dredged from offshore locations and dumped near the coast to create additional land. The sandfill is protected along the shore with a revetment to prevent erosions and flooding from the sea.

Offshore islands are less common. Offshore islands are located a significant distance from shore and do need to have port facilities for access. The offshore islands are often located in deeper waters with higher waves, requiring higher and stronger revetments. Offshore islands have been constructed for oil and gas installation near Canada and in the Caspian Sea.

An offshore energy island is relatively expensive due to large water depth making its construction more challenging, and due to high requirements for the revetment in offshore conditions. A square meter price for an offshore island some 50 to 100 km from the shore would be five times higher than the price of land reclamation in shallow water at the coastline. To keep the construction costs under control it is essential to make a sharp analysis of the required land area and harbour basin for the functions considered. As most of the costs are required for the revetment, combining several functions on an island would reduce the costs per square meter and improve the cost-benefit-ratio for each individual function considered.

In earlier studies (IJvertech, 2019) analyses have been performed for which functions an offshore island would be beneficial and therefore could be combined on an energy island. Following functions were identified:
– offshore Transmission System Operator (HVDC station);
– Power to Gas;
– coast guard (probably required by the Dutch Government);
– data centres;
– operation & Maintenance for offshore wind);
– offshore supply base/marshalling yard for offshore wind.

In the next paragraph we consider an offshore island for three different sets of functions:
1. A standalone island for hydrogen production.
2. An energy island for hydrogen production and electricity conversion.
3. Multifunctional island on which more functions are facilitated.

2.2 Island size and functions

The size of an offshore island is depending on the required functions. In the following sections the land area and port basin area required for three sets of functions, with increasing multifunctionality. General functions as port basin, location for coast guard and use of helideck can be shared between different functions as capacity is only a minor issue, yet a minimum land area is required to provide the service.

2.2.1 Standalone island for hydrogen production

A standalone offshore island for hydrogen production requires land area for a power-to-gas facility, an operations building, workshops, and accommodations. Based on facility size of 2 GW and a staff of approximately ten people a total area of 11 ha has been estimated (see also Appendix A).

On a standalone island the following facilities need to be accounted for:
– a heliplatform to transport the crew (75 x 75 m);
– a quay for transport of material and/or crew (150 x 100 m);
– area for incoming cables from the wind turbines (2 ha[4], combined with pipeline);
– area for the outgoing pipeline for hydrogen (included in area for cables);
– area for the coastguard (assumed at 2 ha, including 100 m quay area).

[4] Area for cables is much less than 2 ha, but most probably cables are installed by drilling underneath the revetment, which requires area the 2 ha.

Applying a net to gross ratio of 20%, the total land area for these additional services is estimated to be 8 ha.

The required quay and ship access to the island also requires a port basin for ships to approach the island in a safe way and have a sheltered place for mooring. For a minimum quay length of 150 to 200 m a port basin of 6 ha is estimated to accommodate a ship of some 150 m length (installation barge).

A standalone hydrogen production island is estimated on 25 ha, 19 ha of land area and 6 ha of port basin.

2.2.2 Energy island for hydrogen production and electricity conversion

For the case of a combined hydrogen and HVDC offshore island, the land requirements of the standalone island still apply. Additionally, area for a 2 GW HVDC-station including HVDC-cable is to be accounted for. For an HVDC station of 2 GW following facilities are assumed to be required: the HVDC-station itself, cable entries to the island, interconnection with the HVDC-cable, operations building, workshop, accommodation, and a quay and port basin. The total gross area for the HVDC station of 2 GW is estimated to be 12 ha, 10 ha of land area and 2 ha of additional port basin. In Appendix A, the breakdown of the area is given.

2.2.3 Multifunctional island

A multifunctional island, which also accommodates other functions will reduce the total costs per square meter and consequently improve the business case for offshore hydrogen generation. For this study we assume that a multifunctional island serving 8 GW of wind farm (the 4 GW of the wind farms in IJmuiden Ver plus the 4 GW in the extension to the north of IJmuiden Ver) would be possible in the area, which will results in the lowest costs for the offshore island in the business case for hydrogen production. The multipurpose island for 8 GW as reported in the IJvertech study (IJvertech, 2019) has been assumed as basis for the multifunctional island, however the HVDC conversion is reduced to 2 GW (as IJmuiden Ver is already expected to be connected to the onshore grid via platforms). Some 11 ha is included for experimenting and testing with new forms of power-to-gas, and 35 ha (land and/or water) is included for future extensions or other functions as hydroculture, recreation or fisheries. This is an optimistic island use in which several functions are combined on an offshore island thus reducing the cost per square meter.

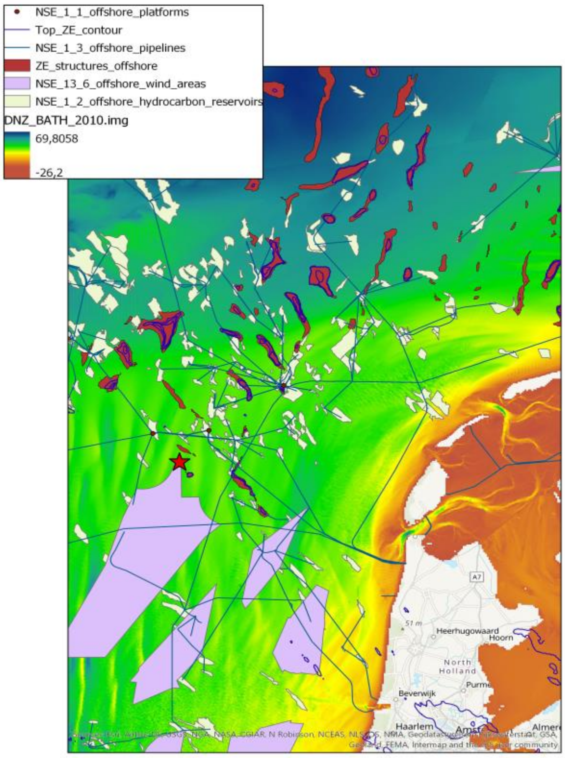
Total area of this island is 114 ha, of which is 18 ha for port basin. Breakdown of the 114 ha is as follows:
- 12 ha for HVDC conversion;
- 2 ha for heliport;
- 22 ha for operation and maintenance support for offshore wind farms;
- 11 ha for hydrogen production;
- 11 ha for other power-to-gas initiatives;
- 17 ha for offshore supply base for windfarm construction;
- 0.5 ha for data centres;
- 3.5 ha for coast guard;
- 35 ha for a future extension and/or other functions.

Depending on the allocation of costs to the different function, the costs for the offshore island allocated to the 2 GW of hydrogen generation would be in the range of 9 to 12%[5] of total investment in the island costs.

2.3 Metocean and geotechnical conditions for the offshore island

This paragraph describes the metocean[6] and geotechnical conditions for the anticipated location of the offshore island. Data are collected from public sources. These data are assumed to sufficiently reflect the conditions at the selected location for the scope of this study. The metocean data are based on the database published by the Netherlands Enterprise Agency for offshore wind projects in the North Sea (DHI, 2019). Data are collected for the location UTM-31 548,493 Easting and 5,891,251 Northing, see Figure 4.

Figure 4 - Overview bathymetric map showing the prospective location of the multifunctional island (red star) and current and future offshore energy infrastructure such as existing pipelines and platforms as well as potential (theoretical) storage sites (hydrocarbon fields and salt structures). Note: DNZ_bath_2010 is the bathymetric map. NSE_offshore platform_ shows the three platforms analysed in this study. NSE_offshore_ pipelines shows the existing pipeline infrastructure, NSE offshore hydrocarbon reservoirs shows the existing hydrocarbon reservoirs (oil and gas). ZE-structures-offshore show existing salt structures and TOP ZE_contour which shows the interval below 1500 meters depth which is considered potentially suitable for salt cavern storage. NSE offshore wind areas shows planned and existing wind areas.



Source: (DHI Group, ongoing).

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5 Higher percentage is reached as area for heliport and port basin are allocated to all users as this will be common facilities.

6 The term 'metocean' refers to meteorology and (physical) oceanography, i.e. environmental conditions relevant for offshore construction of, for instance, an island.

2.3.1 Bathymetry, existing infrastructure, and protected areas

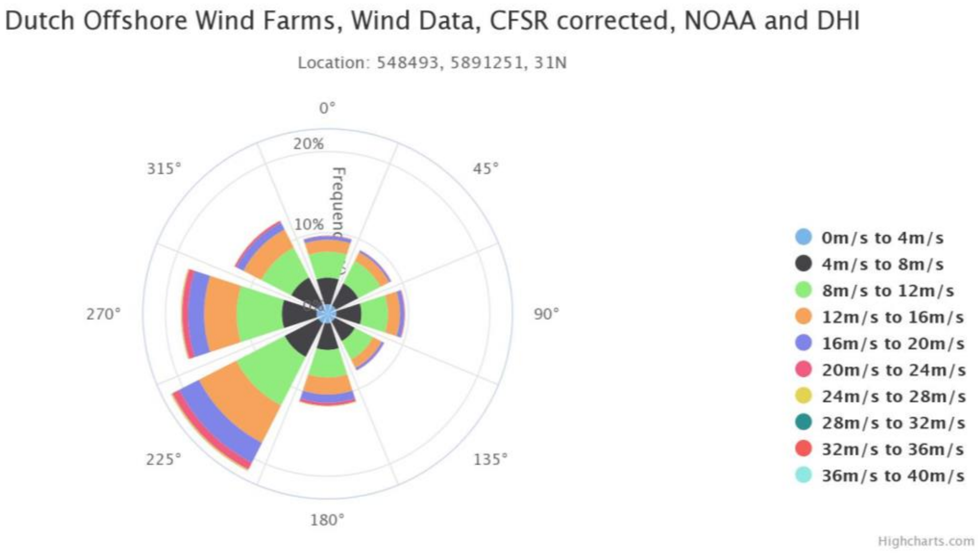
Figure 5 gives an overview of the offshore wind area at IJmuiden Ver and its vicinity, the bathymetry of the North Sea and the existing infrastructure (cables, pipelines and platforms) in the area. No Natura 2000 areas are close to the intended location of the island. The Brown Bank area is the closest one. It lies in the southern part of the wind concession area IJmuiden Ver.

The water depth around the location of the island is 26 m relative to lowest astronomic tide (LAT). Some tidal banks are present, causing variation in water depth of some 4 to 6 m, but the highest tidal banks are located further south.

2.3.2 Wind, currents, and water levels

The wind conditions for the location of the island are given in Figure 5. Dominant wind direction is from the southwest and the west. Wind speeds above 24 m/s on 100 m above mean sea level (MSL) are rare but do occur. Extreme wind speeds (1 per 100 year return period) is some 43 m/s, while the yearly maximum (each year return period) is some 34 m/s, both are 10 minute averaged values (see Appendix B).

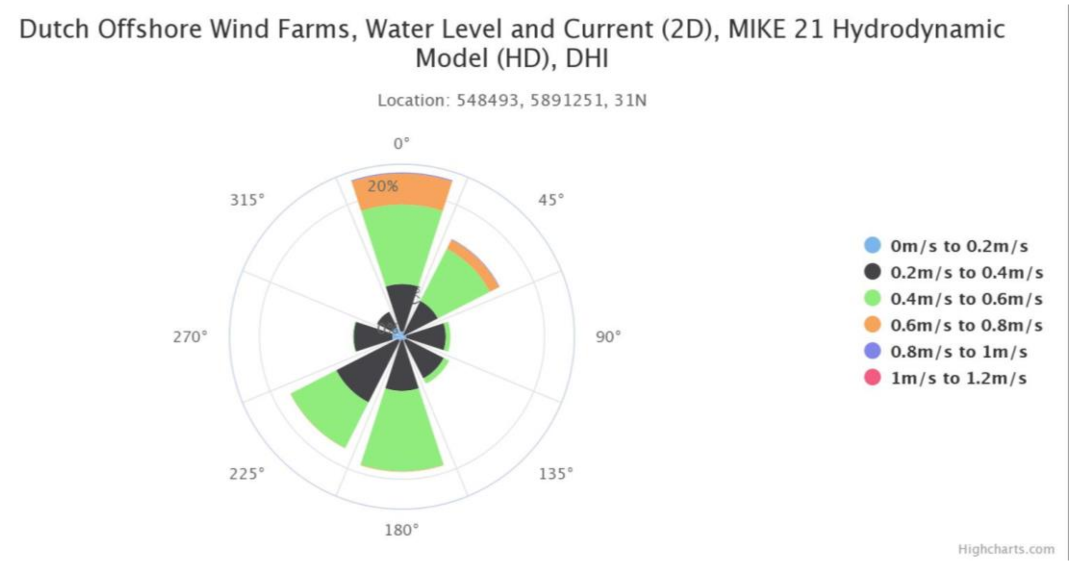
Figure 5 - Wind rose showing wind speed at 100 m above mean sea level on the proposed island location. Wind climate is based on (DHI Group, ongoing) with data from 1979 – 2019



Source: (DHI Group, ongoing).

Figure 6 shows the current rose for the location of the offshore island. Main current direction is to the north, with speeds between 0.4 and 0.8 m/s and to the south and southwest with current speeds of 0.4 to 0.6 m/s. This is in line with the dominant current direction in front of the Dutch coast. Current speed are depth averaged currents. Maximum yearly current speed stays below 1.0 m/s and only in extreme cases (1 per 100 year return period) current speeds of 1.1 m/s can occur (see also Appendix B).

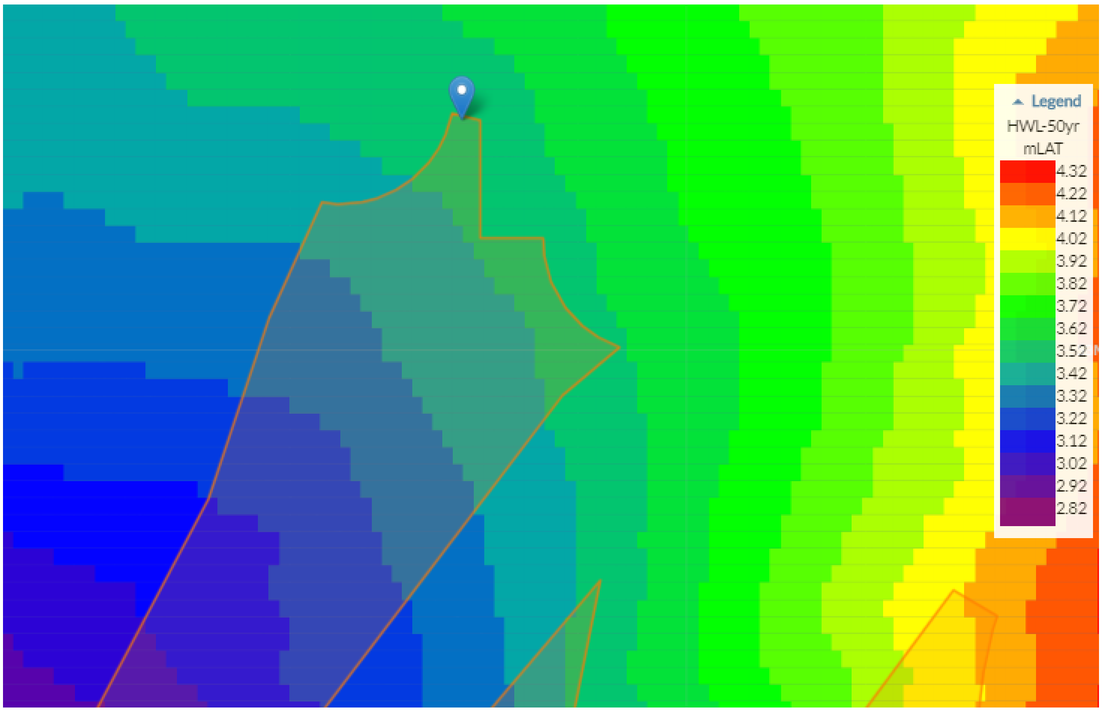
Figure 6 - Current rose showing depth averaged current speed on the proposed island location. Data is taken from (DHI Group, ongoing) with data from 1979 – 2019



Source: (DHI Group, ongoing).

Figure 7 maximum water levels do not vary significantly over the area, the yearly maximum value is calculated as 2.9 m above the lowest astronomic tide (LAT), while the 1 per 100 years condition is 3.6 metres above LAT.

Figure 7 - Overview of maximum water level in 1 per 50 years relative of LAT. Contour line is from IJmuiden Ver windfarm concession area. Data is from (DHI Group, ongoing) with data from 1979 – 2019

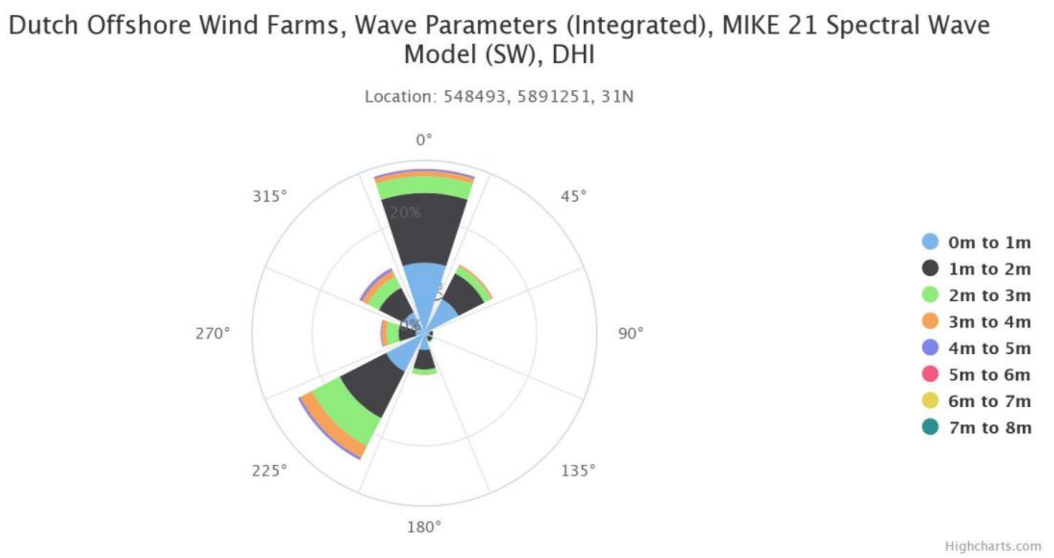


Source: (DHI Group, ongoing).

2.3.3 Waves

In Figure 8 the wave rose is shown for the location of the offshore island. Waves are most frequent from southwest and north, showing the typical wave climate from the North Sea. Waves from the north are somewhat higher and have higher peak periods as they have a swell component coming from the Atlantic Ocean. In the winter period, 60% of the time waves are below 2.0 metres, while in summer this is 95% of the time. The yearly extreme wave condition (each year return period) is 5.6 metres, while the 1 per 100 years significant wave condition is 7.8 metres. Directional information shows that extreme waves from the north are highest and waves from the east are much lower. These conditions are taken into account in the design of the revetment of the offshore island.

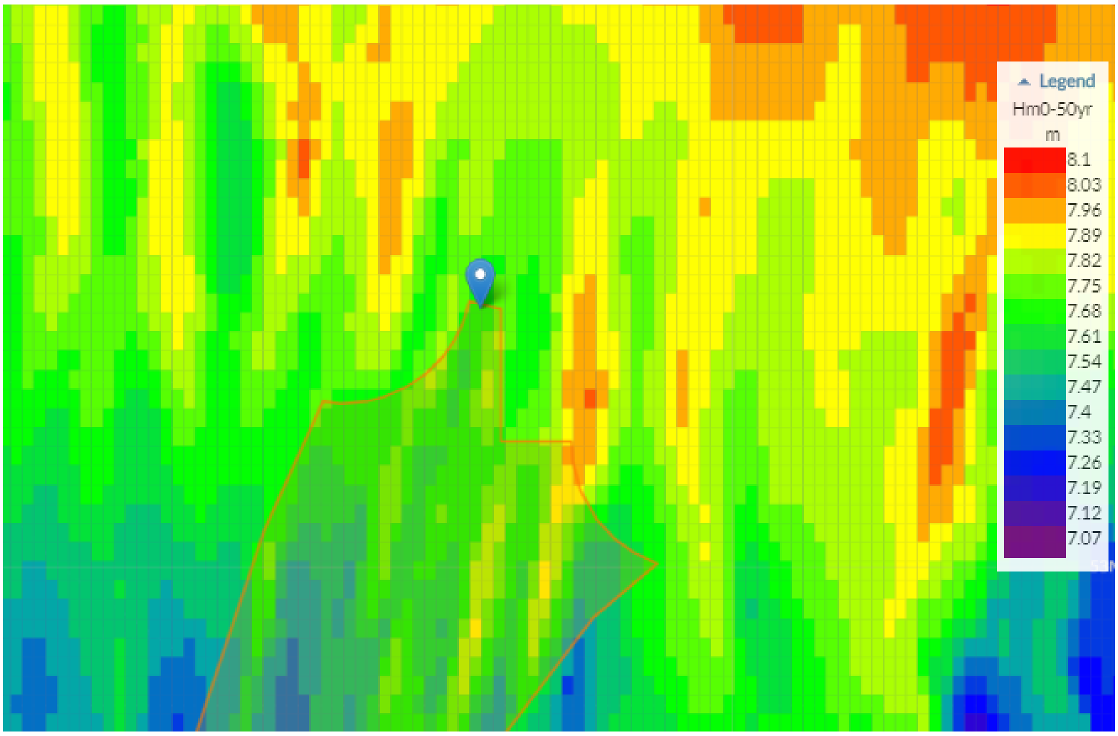
Figure 8 - Wave rose for the location of the island. Data is taken from (DHI Group, ongoing) with data from 1979 – 2019



Source: (DHI Group, ongoing).

In Figure 9 the spatial variation of the extreme significant wave condition is shown. The variations can be related to the variations in bathymetry, but are relatively small in magnitude, within 0.2 m variation in the direct surrounding of the offshore island. Directional variation of the extreme waves is much larger than the spatial variation of the extreme waves.

Figure 9 - Overview of maximum significant wave height 1/50 year. Contour line is from IJmuiden Ver windfarm concession area. Data is taken from (DHI Group, ongoing) with data from 1979 – 2019



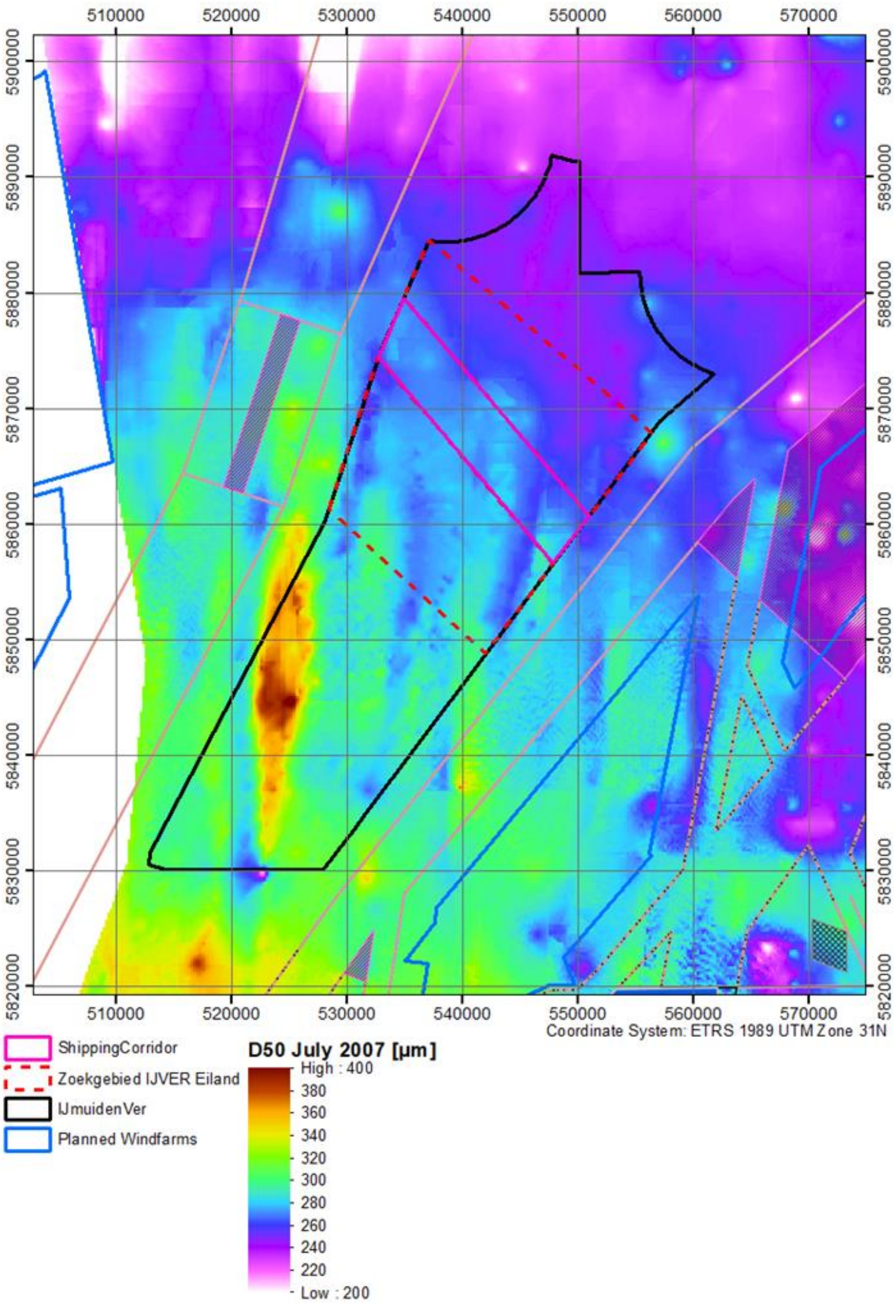
Source: (DHI Group, ongoing).

2.3.4 Seabed characteristics

The seabed at the location of the island is predominantly sand with a D50 around 250 μm, see Figure 10. Variation in D50 around the island is small, medium size sand is located further south near the Brown Bank area. Sediment of 250 μm is suited to construct the island, so it is to be expected that sand for the island can be dredged closeby.

The geology at the location of the island shows that at deeper layers clay is to be expected of the Brown Bank Formation. Although this layer is well consolidated and has lenses of sand, this may lead to settlements of the offshore island. In case of settlement this will be caused by deeper layers and most probably relatively constant over the island. Most common way to take settlements into account is to construct a higher land elevation, so settlements are allowed for. The possible additional construction height is expected to be well within the accuracy of this conceptual design and is therefore not further accounted for in this study.

Figure 10 - Overview of median grain size of seabed sediments



Source: (IJvertech, 2019).

2.4 Design conditions for an offshore island

The metocean and geotechnical conditions as described in the previous section lead to the following design conditions adopted for the design of the offshore island, and especially for the revetment of the island.

Table 1 - Design conditions for offshore energy island

Parameter	Value	Assumption
Location (UTM 31N)	548,493 E; 5,891,251 N	
Water depth (m)	26	Relative to LAT
Maximum water depth (m)	29.6	1/100 year water level
Maximum wind speed (m/s)	43.2	1/100 year, 100 m height, 10 minute average value
Maximum current speed (m/s)	1.1 m/s	1/100 year, depth averaged.
Maximum significant wave height (m)from sector N, W and SW	7.5	1/100 year, 3 hour averaged.
Maximum significant wave height (m)from sector E and SE	5.0	1/100 year, 3 hour averaged.
Seabed	Sand, D50 of 250 µm	

For this study we did assume the 1 per 100 year condition as design conditions. As facilities on the island may be essential for power supply, they may require higher safety standards. In the cost estimates for the island construction (see section 4.3.2) it is recognised that the cost estimate is based on only a preliminary design. A cost surplus is included in the reported construction costs to account for this. Discussion on safety levels are part of this surplus and as such are included in the given values and the associated accuracy percentages of the construction costs.

2.5 Island design

An offshore artificial island at some 80 km from the Dutch coast has specific requirements:

- Severe storms can occur on the North Sea for which especially the borders of the island should be designed upon. This means in particular includes the stability of the revetments around the island and controlled overtopping of these revetments.
- Construction is on open sea, which limits the workability of equipment.
- Water depth is relatively deep for sand reclamation, which requires large volumes of material away from any existing port facilities.

2.5.1 Main parts

The island itself consists of four main parts: the revetment, a 'pancake base', the sandfill for the actual island, and the port basin. We briefly discuss each of these four parts.

To protect the island against damage from storms, a strong revetment at the edge of the reclamation is needed. Due to the water depth and the high storm waves this revetment is to be large and strong and will be close to or exceeds the present experiences for these type of structures. Nevertheless, the present systems for large revetments are believed to be applicable for the island the design will be technical feasible. As the revetment is a major structure for the island, the optimal choice is to reduce the length as much as possible, which would point to a circular-shaped island. Analysis of efficient land use shows that most facilities on the island have a more rectangular shape and in the present study this has been taken as the basis for functional areas.

To reduce the volumes of rock or concrete material the island is constructed on, a so-called 'pancake', i.e. a sand reclamation on the seabed with gentle slopes (1:10 to 1:15) to a water depth of 12 to 15 m. On this 'pancake', the revetment for the edge of the island and the breakwater to protect the port basin are constructed. As sand is a much cheaper material for construction than rock and concrete, this will reduce the total investment costs

for the island. The slopes of the 'pancake' need to be protected against erosion with a gravel layer.
A third major part is the sandfill for the actual island. In the Dutch North Sea sufficient sand is available of good quality (D50 large as 200 μm and fine percentage below 10%) as building material for the island and this is the most economic method for building the island. The sand can be supplied behind the protective revetment. Last part of the sand is to be supplied by pipe or rainbowing. Parts of the island may need to be compacted to have sufficient bearing capacity for the operations on the island.

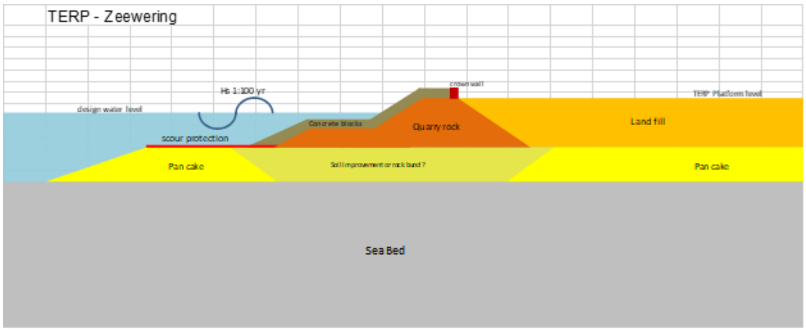
A fourth main part of the island is the port basin with quays and a protective breakwater. The port will be situated at the east or south of the island so it is more sheltered for the dominant storms and easier to enter for ships. Depending on the design, ships to be accommodated by the quays need to have a water depth in front of them from 8 to 12 m, which probably requires a combiwall as most practical quay construction. This type of construction is typical in Dutch ports with such navigational depths. As the breakwater is on the sheltered side of the port, also this structure is well within the experience of marine contractors and only the logistics may require some attention. A typical port basin is 200 by 300 m in dimensions to have sufficient space for navigation and allows for ships up to 150 m to enter and be moored. These ships are most probably needed for the construction of facilities on the island (supply of components to the island) and are also suitable for a future role as an offshore supply base or maintenance and operational base for the offshore wind farms. Transport of crew to the island can be by ship as well as by helicopter, although the latter is probably more expensive. Both modes of transport should be available with regards to safety and/or accidents on the island.

2.5.2 Revetment design

As the revetment is the main protection of the island, we discuss its design options separately. Three type of revetment structures or island solutions can be considered:

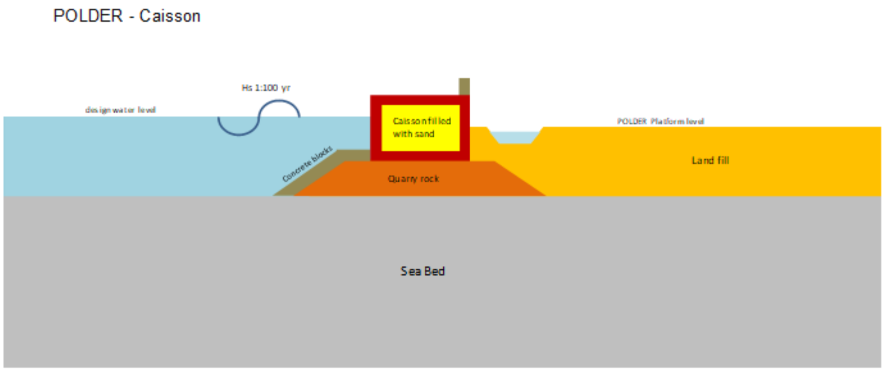
1. A 'terp'-type island, this is a traditional sandfilled island to some 6 metres above MSL with a strong revetment consisting of rock and concrete elements and a seawall on top of the crest (Figure 11).
2. A 'polder'-type island with a lower level of the island (around MSL) and a watertight revetment consisting of caisson type structures (Figure 12).
3. An 'lagoon'-type island with a low crested outer ring and lagoon or lake-like area in which a sandfilled island is constructed for the facilities, or with facilities floating on the sheltered lagoon (Figure 13).

Figure 11 - Illustration of a terp island



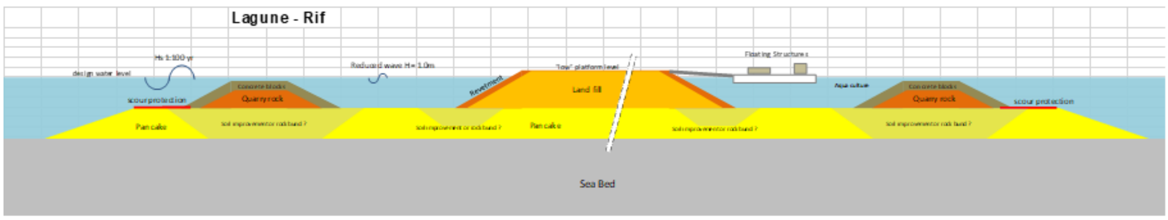
Source: (IJvertech, 2019).

Figure 12 - Illustration of a polder island



Source: (IJvertech, 2019).

Figure 13 - Illustration of a lagoon island



Source: (IJvertech, 2019).

The three revetment types have been analysed in general terms. First cost estimates lead to the following conclusions. Construction costs for the terp and polder islands are similar. The polder-type island, in which a large number of caissons need to be transported and placed in offshore conditions is challenging and is depending on the weather. As such it forms a significant risk for planning as well as for costs. The lagoon-type island is some 10% more expensive in terms of construction costs as the rif revetment along the island is significant longer than a revetment along the edge of the island. The lagoon type island does give more options for a phased development of the island and possibilities of floating facilities.

For standalone island for the hydrogen production, or for the island for hydrogen production and electricity conversion, the terp-type island is preferred as it is likely to have the lowest costs and future (floating) development is not considered in the present alternatives. Following this line, also the multifunctional island is assumed to be of the terp-type.

3 Island Functions and Scenarios

This chapter describes the functions assumed to be present on the island. It further defines the system configuration scenarios of energy transportation between the island and the shore. These scenarios are the basis for the further techno-economic analysis.

3.1 Island use functions and the potential of hydrogen

As foreshadowed in the previous chapters, the core of the multifunctional island concept is the combination of various use functions. We briefly describe different island use functions, and subsequently focus on hydrogen generation as the key function considered in this study.

3.1.1 Island use functions

The multifunctional island is assumed to include a high voltage direct current (HVDC) power conversion station, cable connection facilities, a power-to-gas facility, a coast guard, facilities for operation and maintenance on offshore wind parks including an offshore base or marshalling yard, a heliport, data centers, and, possibly, services for fisheries.

The multifunctionality of the island can have broad benefits in terms of overall costs. Here, it is in particular considered as a means to enable cost-effective onshoring of large amounts of offshore wind energy. A main energy system service function considered for the island is the conversion of alternating current (AC) coming from the wind turbines to direct current (DC) which allows for transport of vast amounts of electricity to shore. Interconnection is also identified as a potential valuable use function and is currently explored by TenneT for the IJmuiden Ver area. Hydrogen production from offshore wind electricity on the island is also studied and could be a potential core functions of an island (North Sea Wind Power Hub, 2019b).

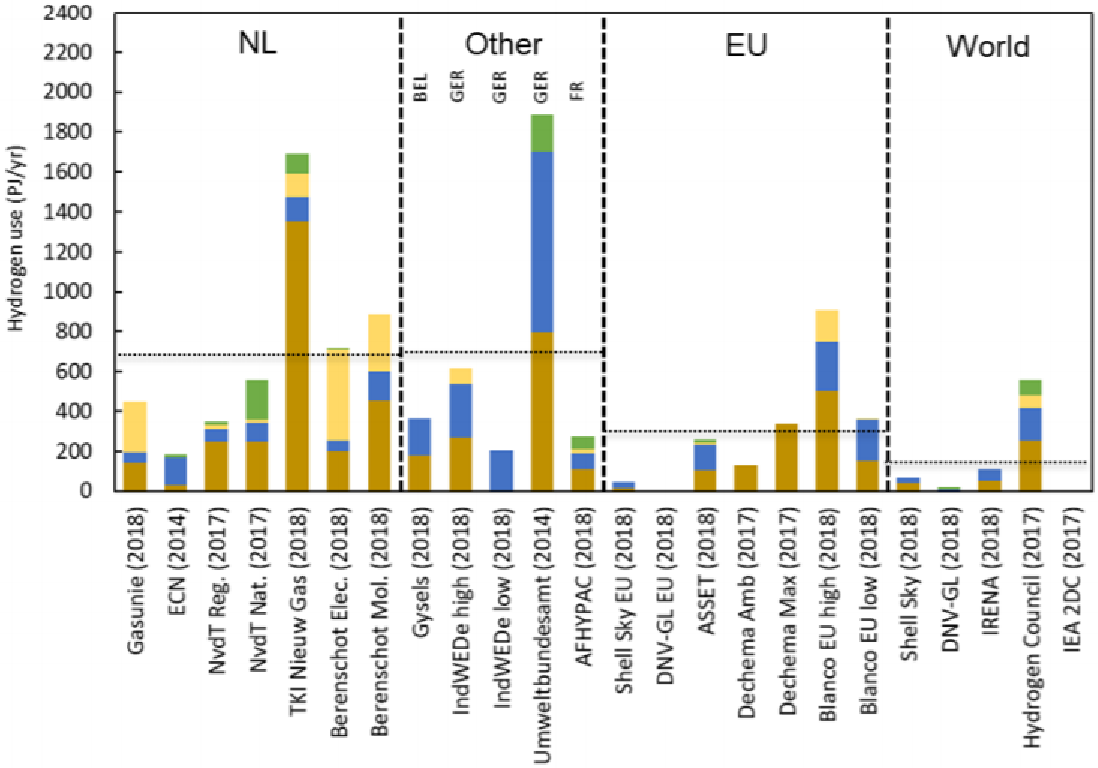
Two functions are considered to be the primary island use functions within the scope of this study: offshore wind collection hub with AC/DC conversion and offshore hydrogen production. Other potential use functions are further discussed in Appendix C.

3.1.2 Potential of hydrogen

There is a consensus that the demand for flexibility in the future (Dutch) energy system will significantly increase. However, there is still uncertainty as to which flexibility instruments will be required and deployed to balance supply and demand in the public gas, electricity, and heat grids, and who is responsible for this change. One of the options to increase the flexibility of the electricity system is to choose for power to gas. In this study, power-to-gas conversion is defined as the conversion of electrical power to hydrogen (on an island or onshore). Power-to-gas could be part of a portfolio of flexibility concepts (i.e. demand-response, flexible production, batteries/storage) to offer the required flexibility.

The demand for hydrogen is thus critical as it determines the future potential and market business case for the conversion of electricity to hydrogen. The multifunctional island at IJmuiden Ver could supply green hydrogen to industrial areas by converting renewable electricity to hydrogen. On a short term, hydrogen application in industry (feedstock and heat production) appears to be the most promising applications next to early opportunities in the transportation sector. In the future, hydrogen could also become important as a replacement for natural gas used for heating in the built environment. Recently published scenarios vary widely on the demand forecast for hydrogen. See for example Figure 14, which shows the widespread in sectoral and total demand in various sectors in the Netherlands.

Figure 14 - Hydrogen use per sector in 2050 (values for other countries or regions besides the Netherlands have been corrected for their relative GDP size).



Source: (TNO, 2019b).

3.2 Assumptions and parameters for defining scenarios

In the following paragraphs we discuss the various assumptions and parameters that are relevant for the setup of different scenarios offshore energy island. The information discussed here is translated to scenarios presented in Section 3.4.

3.2.1 Island location, size, and timing

The location and size of the island, and the timing of its construction depend on a variety of parameters. This section outlines the key parameters involved, including wind capacity, reuse of infrastructure, distance to wind farm areas, timing of wind farm development, as well as the capacity and technology readiness level (TRL) of hydrogen production and conversion.

The timeline to develop and build the island should match with the offshore build-up of wind power. The full extent of the offshore wind capacity in the Dutch continental shelf is currently still under discussion, but it cannot be ruled out that before 2030 an extra effort is necessary to fulfil additional goals of the Dutch and/or European climate policies. The area just north of the current IJmuiden Ver site is one of the likely options to allow for an extended quantity of offshore wind capacity at relatively low costs as it is relatively close to the shore. Areas closer to shore or more to the south are more likely to be reserved for fishery. As far as extra offshore wind capacity is concerned, values between 2 to 8 GW are mentioned, depending on the spatial choices made. Areas which are currently used for military activity and safety zones for offshore oil and gas platforms could potentially be freed up for offshore wind.

After 2030, wind farms will be installed much further to the north. This may lead to the construction of several artificial islands in even bigger wind zones of about 15 GW each. A possible artificial island north of IJmuiden Ver, which is assessed in this study, could serve as a pilot and learning environment for such future wider artificial island applications throughout the North Sea, possibly in collaboration with other North Sea countries.

The optimal location strongly depends on the timing and should take into account the distance to new and existing offshore wind areas. Preferably the island is to be situated close to new areas as the mode of connection and transport of wind energy to shore is not yet fully determined. For the 4 GW allocated to the IJmuiden Ver area the connection type has already been decided. Decisions for further expansions are still due.

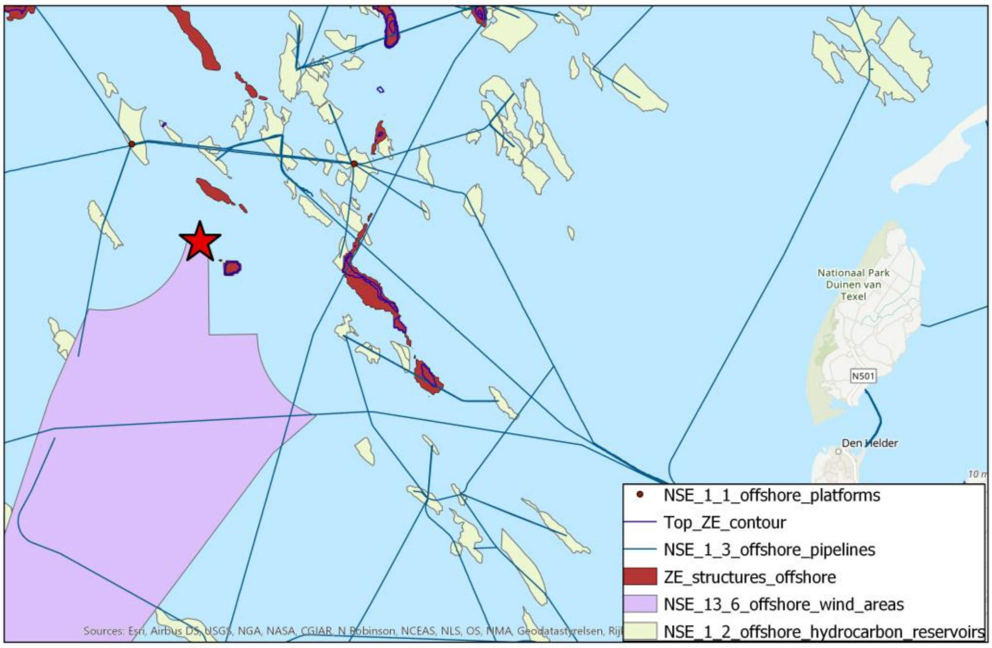
The location should also consider other use functions of the North Sea to avoid spatial conflicts and should consider water depth as this is a leading factor for the construction and costs of the island (see Chapter 2).

Decisions on the conversion infrastructure for hydrogen depend on the capacity of hydrogen production, the technology readiness level, and the strength of the supply chain of hydrogen conversion and processing equipment. Capacity within the gigawatt range for offshore hydrogen production is most likely needed to deliver sizable flexibility to the electricity grid. This is necessary to avoid cost of electricity transport and conversion infrastructure and reach economies of scale needed to have a positive return of investment on the island. Finally, electrolyser producers should have a proven technology and a supply chain in place to deliver the GW size range.

The scope of energy conversion infrastructure and related amenities to be located on the island determine the size of the island. Small conversion infrastructure is more easily and cost effectively realised on a platform, for which TenneT also has standardised solutions at approximately 700 MW; and is working on 2 GW solutions AC/DC (525 kV) for wind farms further offshore. The latter concept is to be applied to the first 4 GW wind farm in the IJmuiden Ver wind area. The construction of multiple smaller islands is also the solution suggested by the consortium in the North Sea Wind Power Hub program (TenneT, 2019). To reach economies of scale, the island should have conversion infrastructure in the multiple GW range and thus an offshore wind farm connected that surpasses at least the 1 GW size.

With these reflections in mind, a prospective location and timeline for the island has been sketched. The prospective multifunctional island is foreseen to be located in the northern tip of the currently planned IJmuiden Ver offshore wind farm (see Figure 4 in Chapter 2 and Figure 15). This location has been selected because it is the likely extension of wind capacity in this area. Plans for a 2 GW extension of IJmuiden Ver to the north are being considered. This 2 GW of wind energy could be considered for connection to the multifunctional island and forms the basis of the development of our scenarios.

Figure 15 - Detailed map showing the prospective location of the multifunctional island at the northern tip of the IJmuiden Ver wind area (red star) and current and future offshore energy infrastructure nearby such as existing pipelines and platforms as well as potential (theoretical) storage sites (hydrocarbon fields and salt structures). NSE_offshore platform shows the three platforms analysed in this study. NSE_offshore_pipelines shows the existing pipeline infrastructure, NSE offshore hydrocarbon reservoirs show the existing hydrocarbon reservoirs (oil and gas) (all NSE items are derived from the North sea energy atlas developed in the NSE3 project (North Sea Energy, 2020d)). ZE-structures-offshore show existing salt structures and TOP ZE_contour which shows the interval below 1500 metres depth which is considered potentially suitable for salt cavern storage. NSE offshore wind areas show planned and existing wind areas

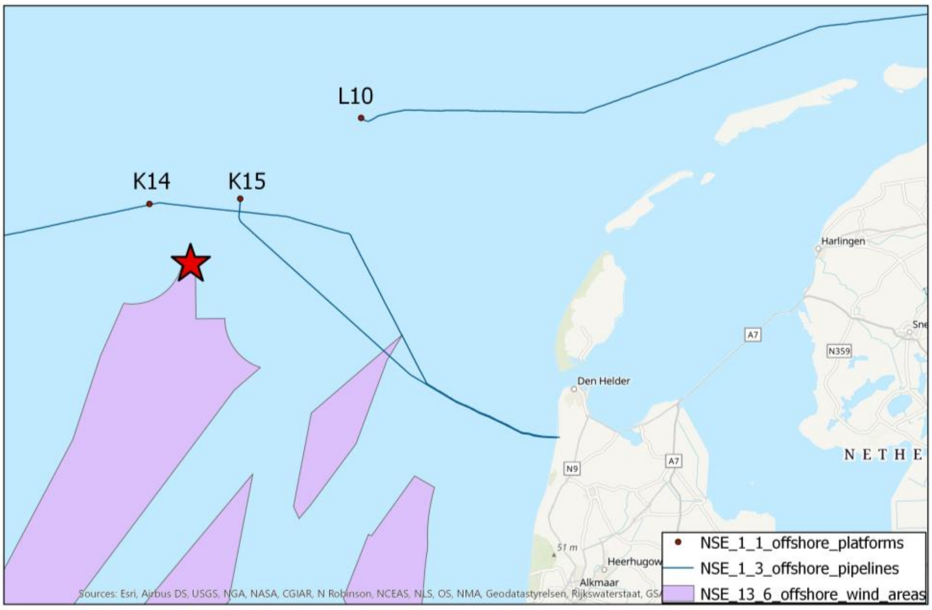


For our scenario analysis, we assume that the IJmuiden Ver extension and all island functions are fully operational by 2030. This would entail enough time to develop and construct the island. We assume a rough timeframe of four years of design and permitting (2022-2026) and four years of construction and start-up (2026-2029). Moreover, by 2030 also the energy mix in the Netherlands is likely to have changed, with more feed in of (variable) renewable sources like wind (off- and onshore) and solar. It is therefore more likely that there is a higher need for flexibility in the energy system and a potential for power to hydrogen as part of the solution. We assume a lifetime of 25 (20-30) years for the wind farm, meaning that operations will continue until at least 2050. For a detailed description of the island infrastructure and size, see Chapter 2.

3.2.2 Reuse of infrastructure

Reuse of oil and gas infrastructure might reduce the cost of bringing hydrogen to shore. In a previous study, reuse of gas pipelines on the North Sea was identified as a potential positive factor in supporting the business case for an offshore energy island. (DVN GL, 2018).
The technical characteristics, location and availability in time are crucial factors when considering reuse.

Figure 16 - Location of platforms and pipelines in the vicinity of the multifunctional island. The star indicates the location of the island



Source maps: (North Sea Energy, 2020b)

For the location under consideration in this study, three major gas pipelines are located nearby the chosen location: NGT, WGT, LOCAL. Figure 16 shows the location of these pipelines in relation to the location of the island, and Table 6 provides an overview of their technical characteristics. Under our current technical assumptions of pressure and flowrate, all three pipelines have large enough capacity to transport the hydrogen produced on the island at peak wind capacity (i.e. multiple GW). However, some uncertainty on this arises from discussions on final pressure and flowrate assumptions that are suitable for hydrogen transport in existing natural gas pipelines. This is explored in more detail in Section 5.7.5.

The connection of the island with existing infrastructure is foreseen at existing platforms. At a distance of roughly 16 kilometres the platforms K14 and K15 are located. They are used as feed-in platforms for respectively the LOCAL and the WGT pipelines, which are thus located relatively close to the island location. The feed-in platform L10 to the NGT pipeline is located at a distance of 41 km. Despite the larger distance to this feed-in platform, it is still a relevant option compared to new pipelines because reusing the NGT pipeline could avoid lengthy permitting and construction periods.

Table 2 - Overview of technical characteristics of WGT, LOCAL and NGT pipelines

Evacuation pipeline	Feed-in platform cluster	Platform distance to island (km)	Diameter (inch)	Hydrogen capacity (GW)*	Hydrogen flow rate (ton/h)	Onshore gas treatment location
WGT	K14	13	36	5.02	127.4	Den Helder
LOCAL	K15	16	24	2.16	54.9	Den Helder
NGT	L10	41	36	5.02	127.4	Uithuizen

***HVV (142 MJth/kg hydrogen) at a pressure of 35 bar and a flowrate of 20 m/s. As a result of an estimated P2G efficiency of 63,5% (based on LHV), an electrolyser with a nominal capacity (input power) 40% larger than the capacity of the pipeline can be connected. (source:** (North Sea Energy, 2020c).

Nexstep (Nexstep, n.d.) developed decommissioning scenarios for all offshore platforms. In the case of the 'most likely' scenario the K14-platform and the K15-platform will be in use beyond 2027. For the L10-platform the decommissioning is likely to start between 2023-2027. It should be noted that these dates are rather uncertain. The North Sea Energy Atlas states: 'It is very difficult to estimate the exact date of decommissioning as this depends strongly on (external) market and production factors, such as: gas price, new exploration nearby, production volumes, operational cost developments, and the decommissioning strategy (e.g. joint campaigning). This is why the industry provides indicative dates'. (North Sea Energy, 2020b).

These decommissioning rates are essential for timing and construction of the island. If pipelines and platforms are not available within the foreseen timeframe for hydrogen production on the island, hydrogen transport would have to be done by admixing. In that case the product will become a hydrogen-natural gas mix, which influences the transport capacity of the hydrogen, the end-use applications, and related market price for hydrogen. Be it the case that there are no pipelines available for reuse, a new pipeline will have to be constructed.

Section 4.3.5 provides a detailed analysis on reusing an existing trunk line based on the assumption that at least one of these large trunk lines (WGT, NGT or LOCAL) will be completely available for hydrogen transport by 2030. This analysis includes the criteria set for the ultimate pipeline routing, the technical feasibility, and the investment required.

3.2.3 Hydrogen production capacity

The assumed connected wind power for the island is 2 GW. The maximum installed hydrogen production capacity depends on the scenario. We use four scenarios. In three of the four scenarios we assume a maximal power-to-gas facility capacity of 1.9 GW, taking into account system inefficiencies and losses. In the fourth scenario, we employ two cases. In the first case we also assume a hydrogen production capacity, in the second we optimise the production capacity. See Section 3.3 for a more detailed description of the scenarios, and Chapter 4 for the optimisation of the hydrogen production capacity.

3.2.4 Location of electricity and hydrogen onshoring

The scenarios cover different options for onshoring of wind energy, either in the form of electricity or hydrogen. Here, we discuss the suitability of different onshoring locations of (reused) pipelines and the suitability of different options for electricity onshoring and subsequent conversion to hydrogen. Section 4.3.5 describes a detailed analysis of the techno-economics of reusing pipeline infrastructure for hydrogen transport.

For the year 2030 we assume the presence of an onshore hydrogen backbone, for onshore hydrogen transportation (see Figure 17). With this backbone in place we assume that hydrogen is priced uniformly across the Netherlands, yielding no preferred point of landing steered by the price of hydrogen. Also, the costs for electricity conversion and transport infrastructure is assumed to be similar for the different locations under consideration. Below we provide a further comparison between onshoring locations for hydrogen and for those for electricity.

Figure 17 - Existing hydrogen infrastructure

Source: (Ausfelder, et al., 2017, p. 174)

Onshoring locations of reused pipelines

The onshoring location of existing pipelines determines the potential location of hydrogen input in the onshore backbone when these pipelines are reused for hydrogen transport.

Groningen/Eemshaven (NGT)

Hydrogen demand is currently limited in the Groningen region. However, Groningen is involved in a number of initiatives on the production and consumption of hydrogen for industrial, transportation, and energy applications. The demand for hydrogen is therefore expected to increase. As a result, the “Groene Waterstofeconomie in Noord-Nederland” report foresees a total hydrogen production of 270 kton (38 PJ) in Northern Netherlands by 2030 (NIB, 2017). In the recent TIKI report ((DNV GL, 2020) the North of Netherlands cluster is estimated to have a demand growing towards 30-70 PJ in 2030.

In addition, Groningen is connected to other industrial demand centers through existing gas infrastructure which might be reused to create a hydrogen backbone allowing for large scale hydrogen transport. Finally, Groningen is close to possible large-scale hydrogen storage locations.

Den Helder (LOCAL, WGT)

There is currently no significant demand for hydrogen in the Den Helder region. Several initiatives to study the potential role of Den Helder as a hydrogen hub have been started (see e.g. (TNO, 2019b)). There is a feasibility study started towards a blue hydrogen production facility in Den Helder[7]. Similar to the Groningen port region, the Den Helder and Amsterdam port regions could become hydrogen hubs in the future.

Den Helder is well suited to act as a transport hub for hydrogen produced offshore. Two relevant large pipelines (LOCAL and WGT) land near Den Helder. The Nederlandse Aardolie Maatschappij (NAM) operates large gas treatment facilities near Den Helder, which could be used for hydrogen treatment before feeding into further transport infrastructure. If Den Helder is connected to a hydrogen backbone, hydrogen can be transported to large demand centres in industrial complexes and possibly to storage locations. As the onshoring location of the LOCAL and WGT pipelines, Den Helder can be considered a potentially suitable location for onshoring of hydrogen generated offshore.

Locations for electricity onshoring and hydrogen production

For effective onshoring and conversion of up to 2 GW of DC electricity, a 380 kV-station must be present and enough physical space must be available for AC/DC conversion systems. For the first phase of the IJmuiden Ver wind farm, a number of electricity transport cable routes and onshoring locations were shortlisted by Pondera & Arcadis (2018a; 2018b). Here, we briefly discuss the suitability of a number of these options as onshoring locations for the multifunctional island at IJmuiden Ver.

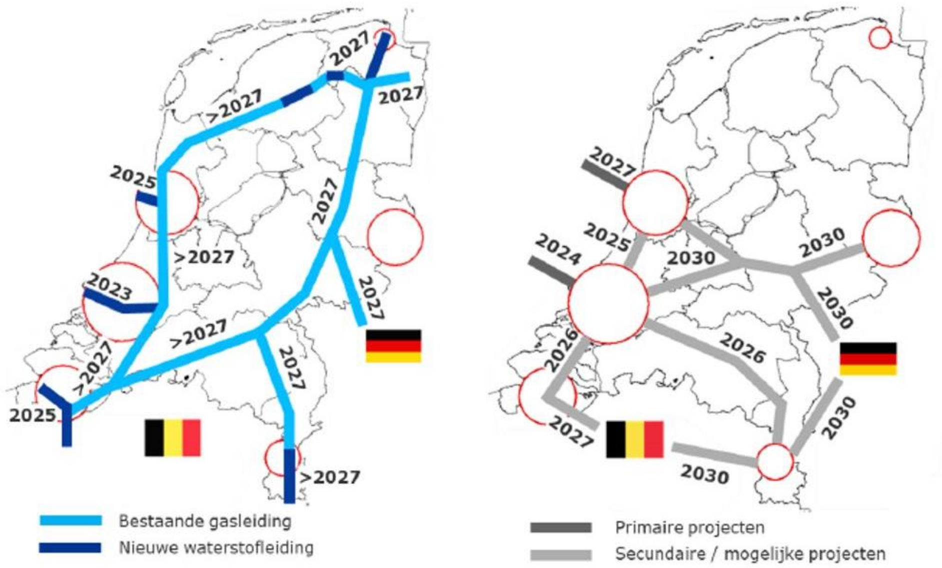
Maasvlakte/Rotterdam

Currently the Port of Rotterdam industrial complex is the largest consumer of hydrogen in the Netherlands. Hydrogen is mainly used for refining and in the chemical industry. A hydrogen pipeline already connected Rotterdam to other industrial centres in the Netherlands, Belgium, and France (see Figure 18). The vision of Port of Rotterdam even envisages to transport hydrogen to Germany (Ruhr area) via pipeline.

Hydrogen is currently produced through reforming of natural gas (so-called ‘grey hydrogen’). Plans exist to include hydrogen production using carbon capture and storage (so-called ‘blue hydrogen’) and through electrolysis (so-called ‘green hydrogen’). Decarbonisation pathways for the Port of Rotterdam calculated by the Wuppertal Institute (Wuppertal Institute, 2016) suggest that in 2050, 2.5 to 6.4 GW of electrolyser capacity is needed to meet the hydrogen demand of local industry in a carbon-neutral way. In addition, the Port of Rotterdam sees an opportunity to act as a transport hub for hydrogen towards the rest of the Netherlands, as well as the large industrial complexes further downstream in Europe. For these reasons, the Maasvlakte would be a suitable onshoring location. Use of oxygen and heat as by-products from electrolysis in industrial processes might have valuable synergy in the harbour area.

7 Gemeente Den Helder : Blauwe waterstoffabriek in Den Helder in zicht

Figure 18 - Potential hydrogen infrastructure and timeline



Source: (DNV GL, 2020).

Beverwijk

In a recent publication commissioned by the ministry of economic affairs (Pondera Consult ; Arcadis, 2019) the Beverwijk location was excluded as landing point for electricity.
The analysis performed indicated that there was not sufficient space available near the 380 kV station of Beverwijk for a HVDC-station.

However, with also hydrogen production in the equation this location is very relevant and of high interest. The largest consumer of energy in the Beverwijk area is Tata Steel Europe. Research is being conducted to study the possibility of using hydrogen in several phases of the steel production process. As a result, hydrogen consumption could grow substantially by 2030.

A consortium named H_2ermes of Tata Steel, Nouryon, and the Port of Amsterdam is studying the feasibility of a 100 MW hydrogen production plant on the Tata Steel site.[8] The ambition for further scale-up is highlighted by the consortium.

In addition, the report on carbon neutral aviation assessed the potential of the North Holland region for the production of e-fuels (Terwel & Kerkhoven, 2018). These e-fuels can be used for carbon neutral aviation. To synthesize kerosene a source of CO_2 and of hydrogen is needed. The CO_2 can be provided by Tata steel which is one of the largest emitters in the Netherlands. The hydrogen can be supplied from the IJvergas Island. The kerosene can be then supplied to Schiphol airport, which is one of the largest airports in the world in terms of passenger traffic.

8 Port of Amsterdam : Nouryon, Tata Steel en Port of Amsterdam werken samen aan project H2ermes: groene waterstof voor de regio Amsterdam

In the recent TIKI report (DNV GL, 2020) the North Sea channel area cluster is estimated to have a demand growing towards 2.3-23 PJ in 2030 and towards 16-88 PJ in 2050.

Onshoring of new pipelines

Reuse of existing pipelines could be turn out infeasible for various reasons. One main reasons is the availability of existing pipelines. If these pipelines are not freed up in time and if admixing is not possible, a new pipeline might be necessary. Another issue might be the age and status of the pipeline. If a pipeline is too old, it cannot be repurposed for hydrogen transport. Finally, a pipeline could already be repurposed for another use, for instance CO_2 transport.

The locations suitable for onshoring of new pipelines remain largely the same as the onshoring locations of existing pipelines. From the perspective of demand the only location that might be less suitable is Den Helder. Den Helder has no significant hydrogen demand and is mainly considered because the LOCAL and WGT pipelines, which are candidates for reuse, come on shore there. However, Den Helder is relatively close to the IJvergas island location, resulting in lower cost for a new pipeline, compared to other onshoring locations.

3.3 Description of selected scenarios

We distinguish four scenarios of wind energy conversion and transportation from the wind park to the shore. The four scenarios are designed to unravel specific effects of design choices of the island energy services. The scenarios differ by the degrees of freedom for converting and trading wind power.

The scenarios consist of two sets. In Scenarios 1 and 3, electricity is brought to shore, and hydrogen is generated on shore. In Scenarios 2 and 4, wind power is brought to the island, where it is partly or entirely converted to hydrogen. In Scenarios 1 and 2, the entire wind capacity of the connected wind farm is used to produce hydrogen. In Scenario 1, hydrogen can also be produced using electricity from the onshore grid, however, we assume that the wind farm cannot sell its electricity to the onshore grid. In Scenarios 3 and 4 only part of the electricity from the wind farm is used to produce hydrogen. In Scenario 3 and Scenario 4, maximal cable case, the power-to-gas facility has a maximal capacity of 1.9 GW.
In Scenario 4, optimal cable case, the size of the power-to-gas facility is optimised.

Figure 19 shows a schematic overview of the scenarios. Table 3 provides an overview of the assumptions. The following paragraphs describe the onshoring assumptions, and their effects for each of the scenarios.

Figure 19 – System configuration in the four scenarios.

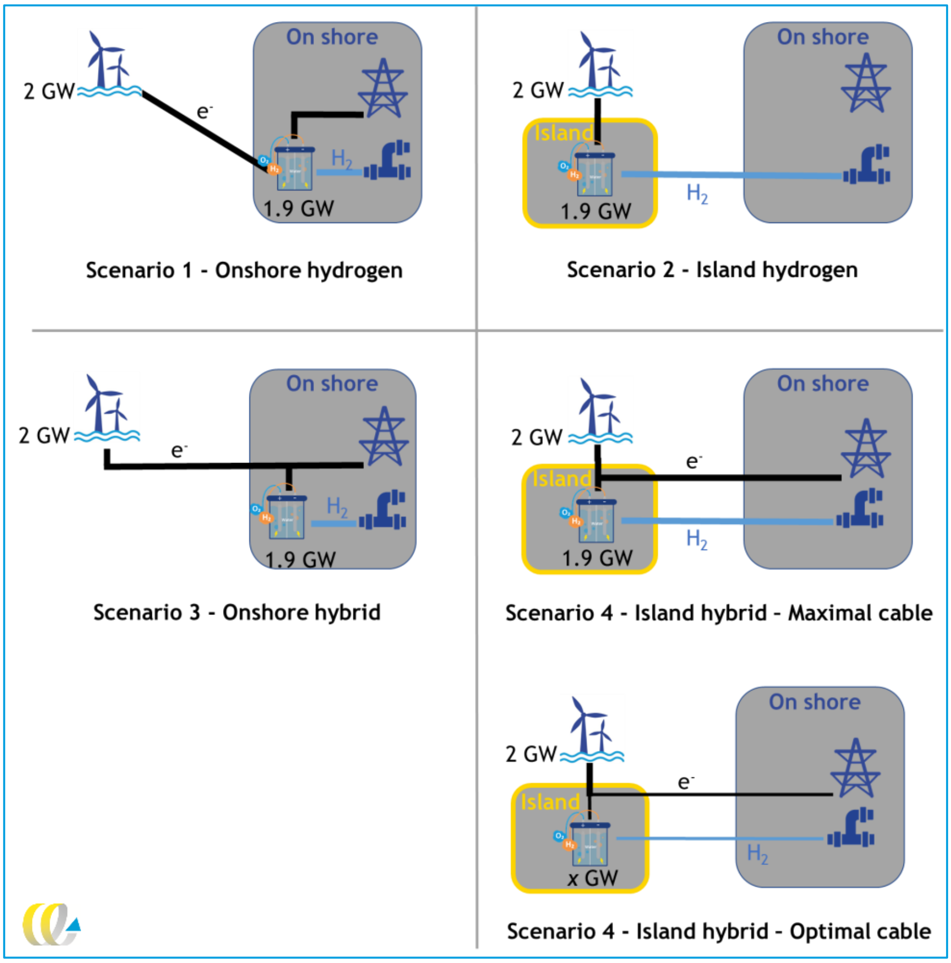


Table 3 - Detailed overview of the assumptions in the four scenarios

Scenario	Years of operation	Wind capacity	Power-to-gas location	Power-to-gas capacity	Share of wind converted to hydrogen	Hydrogen onshoring	HVDC-station location	DC cable capacity	AC/DC conversion	Cable onshoring location
Scenario 1 - Onshore hydrogen	2030-2050	2GW	Beverwijk	1.9 GW	100%	None	Platform	2 GW	2 GW	Beverwijk
Scenario 2 - Island hydrogen	2030-2050	2GW	Island	1.9 GW	100%	Den Helder	Island	None	None	None
Scenario 3 - Onshore hybrid	2030-2050	2GW	Beverwijk	1.9 GW	Variable	None	Platform	2 GW	Up to 2 GW	Beverwijk
Scenario 4 - Island hybrid	2030-2050	2GW	Island	Up to 1.9 GW	Variable	Den Helder	Island	Up to 2 GW	Up to 2 GW (with a maximum equal to DC cable capacity)	Beverwijk

3.3.1 Selected onshoring locations electricity and hydrogen

Beverwijk is selected as the onshoring location for electricity for the scenarios. The main reason for this choice is the proximity to the demand for hydrogen and plans by industrial parties and the Port of Amsterdam to develop this area as one of potential hydrogen clusters. The IJmuiden Ver Alpha and Beta offshore substations will most likely have their HVDC landing points within the Rotterdam/Maasvlakte industrial cluster. This industry cluster also has announced studying the feasibility of large scale hydrogen production plants.[9] We assumed that if the IJmuiden Ver wind area is expanded with 2 GW of wind capacity it would be beneficial to spread the landing of this energy (either as electricity and/or as hydrogen) to another cluster, in our case the IJmuiden/Amsterdam cluster.

In the case of bringing hydrogen produced offshore to the mainland, the location of Den Helder is chosen as this location already is one of the major onshoring hubs for natural gas pipelines and it offers potential for the reuse of pipelines. The area hosts the landing of evacuation pipelines for offshore produced natural gas, as well as the Balgzand Bacton Line (BBL) interconnecting pipeline between the UK and the Netherlands. This hub function could be expanded with hydrogen onshoring from offshore production.

3.3.2 Four system configuration scenarios

In Scenario 1 — onshore hydrogen, the net available wind electricity is landed onshore at a location near Beverwijk connecting to the industrial cluster of IJmuiden and the Port of Amsterdam. The wind energy comes on shore as electrons via DC cables. AC/DC conversion offshore is placed on a platform. On shore, all the electricity (2 GW minus conversion and transport losses) is converted to hydrogen (for detailed operational scenarios see Chapter 4). The onshoring location has a 525 kV-station and power-to-gas facilities with a connection to the hydrogen backbone. The net capacity of both the power-to-gas facility and the connecting power cable is 1.9 GW. This assumes a net capacity of 95%, taking into account losses from wake effect and collection system. The power-to-gas facility is also connected to the national electricity grid. When wind generation is below 1.9 GW, the power-to-gas facility can thus use additional electricity from the grid.

In Scenario 2 — island hydrogen, the electricity is transported from the wind farms to the IJvergas island. On the island the electricity is fully converted to produce hydrogen. There is no power cable from the island to shore. The hydrogen is then transported to shore through either a reused pipeline, or a new pipeline (see Section 3.2.2). In this scenario there is no electricity cable between the island and the shore. At the onshoring location near Den Helder the hydrogen is directly used or fed into a hydrogen backbone and transported to demand clusters.

Scenario 3 — onshore hybrid is a hybrid scenario similar to Scenario 1. In this scenario the electricity is also collected on an AC/DC platform and transported to shore. At the onshoring location, it is used to produce hydrogen or converted to AC electricity. The maximum capacity of the power-to-gas facility is again 1.9 GW. The difference with Scenario 1 is that in this scenario part of the generated electricity can be sold as such to the onshore grid. The share of power used to produce hydrogen depends on the value of hydrogen and on that of electricity (see next chapters).

[9] Maritiem Nederland : Shell bouwt groene waterstoffabriek in Rotterdam

Scenario 4 — island hybrid is similar to Scenario 2, but again with a hybrid conversion of hydrogen and electrons. This scenario has two subcases: Scenario 4-maximal cable and Scenario 4-optimal cable. In Scenario 4 — maximal cable, the capacity of both the power-to-gas facility and the power cable is 1.9 GW, similar to Scenario 3. In Scenario 4 — optimal cable, the capacity of the power-to-gas facility and the power cables are optimised (see Chapters 4 and 5).

4 Techno-economic background of scenarios

This chapter describes how the technical island design and construction from Chapter 2 and the four scenarios defined in Chapter 3 are translated into a techno-economic supply chain model. System boundaries of that model and general techno-economic assumptions behind the supply chain modelling are described and explained in the following sections. The techno-economic assessment of the selected scenarios is strongly affected by varying commodity prices and by the required process infrastructure characteristics. Section 4.1 dicusses the system boundaries including a process overview and market circumstances consisting of future electricity and hydrogen prices that determine the optimal energy management strategy of a power-to-gas system. The capital and operational investments required for the realisation of the energy sytem infrastructure are discussed in Section 4.3. More general factors such as the investment climate, the timing of construnction and operation, and, for instance, the offshore wind profile are summarised in Section 4.4. The results of the scenario-based value chain modelling are presented in Chapter 5.

4.1 System boundaries

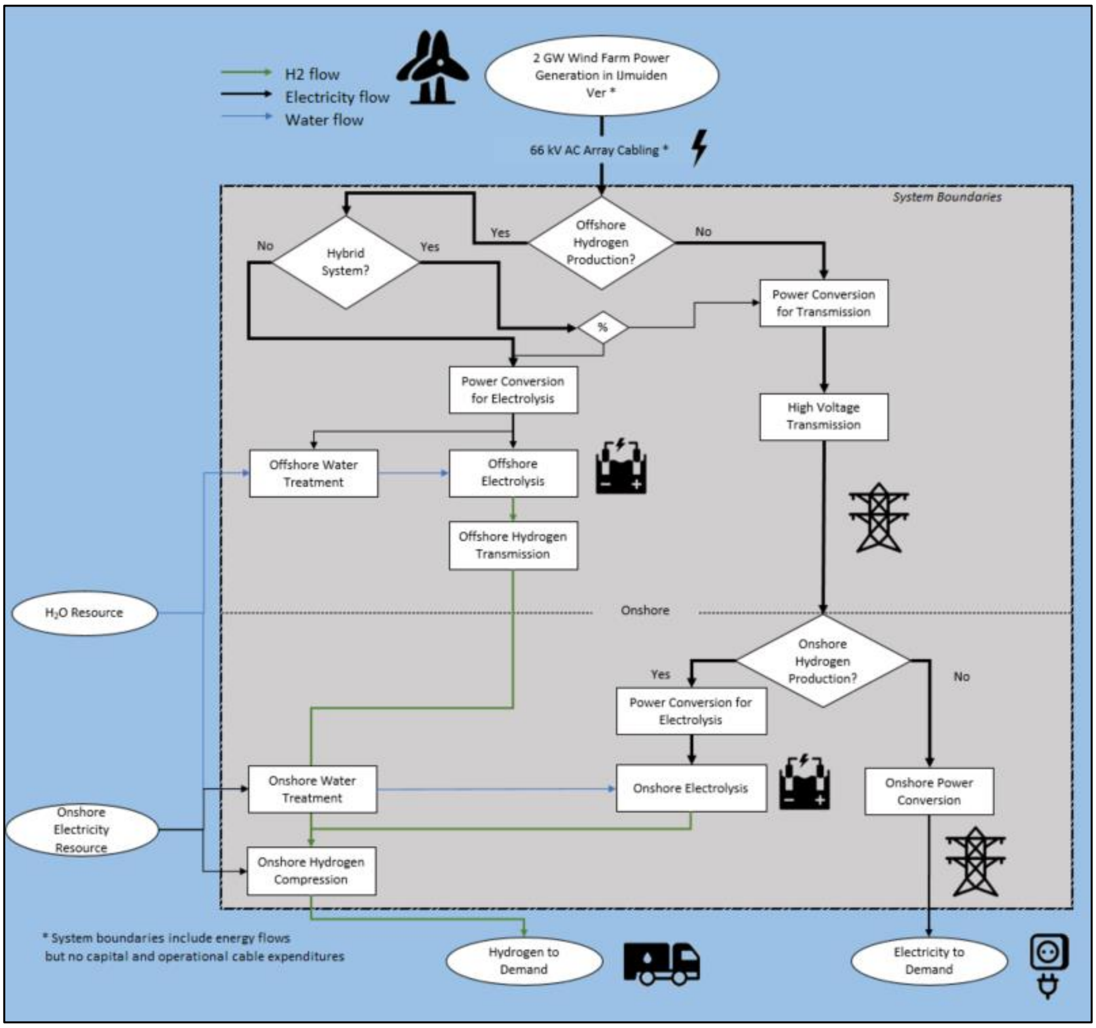
For the techno-economic supply chain modelling, the scenario descriptions focus on electric transmission and power-to-gas conversion (see Section 3.3). These functions and their most relevant processes have have been translated into a process flow chart (Figure 20 - Schematic overview of the techno-economic system boundaries).Processes considered to be within the system boundaries are: electrolysis, power conversion and transmission process, and auxiliary processes such as water treatment and hydrogen compression.

The main input for the considered system is the electricity of an assumed 2 GW wind farm extension at IJmuiden Ver, and its dedicated array system (see also further, Section 4.4.2). Wind power enters the system boundaries and, depending on the scenario, is used for different purposes. The main differences are the location of hydrogen generation (offshore or on shore), and the the share of electricity used for the power-to-gas process. All electricity is subject to offshore AC/DC conversion to reduce transport costs. The final output of the process is the amount of hydrogen produced and electricity sold.

The onshore system boundaries are defined as the onshore substation and/or the onshore P2G facility, depending on the scenario chosen. The functionality of these facilities is outlined as follows:

- Onshore substation: Electricity is collected and converted to onshore grid standard of 380 kV AC and valued according to market prices (see Section 4.2). The subsequent distribution of electricity to the final customer are out of scope.
- Onshore power-to-gas facility: Hydrogen is collected onshore and pressurized to a pipeline inlet pressure level of 50 barg. The subsequent distribution processes of hydrogen to final customers are not left out of scope. Hydrogen is valued against a fixed price (see Section 4.2.3).

Figure 20 - Schematic overview of the techno-economic system boundaries

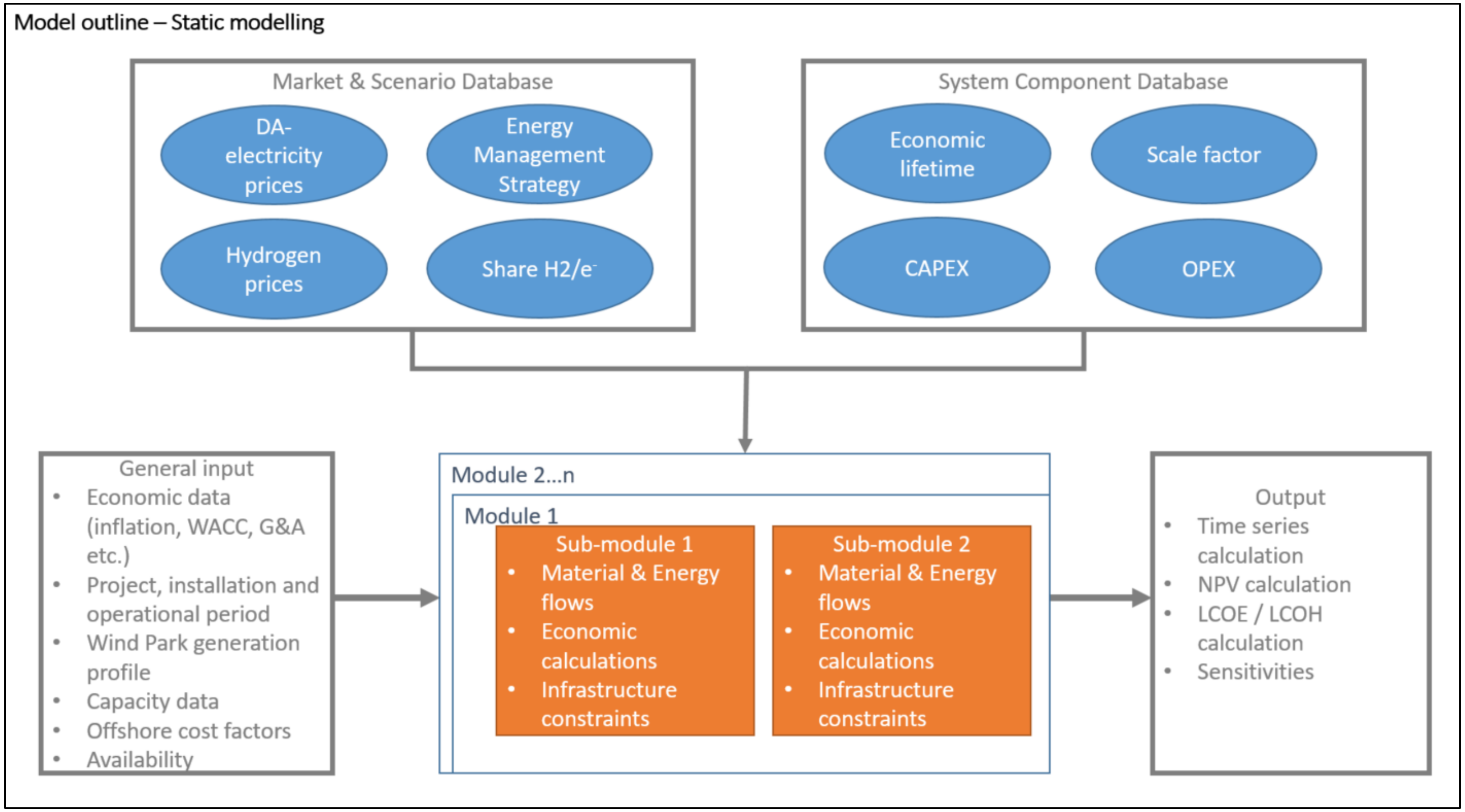


The system boundaries within the various scenarios are translated into a techno-economic model which follows the concept of a Material and Energy Flow Analysis (MEFA), combining material flow analysis (MFA) accounting for mass flows such as water required for the electrolysis process and its hydrogen and oxygen output, with energy flow analysis (EFA) (including required electricity to power the water treatment plant) (Haberl & Weisz, 2006) (Pierie, et al., 2016).[10]

The MEFA structure enables us to transparently measure all relevant flows of a complex process and to link them to their economic impact on the business case. Factors such as the required electricity for the water treatment process, compression, and the hydrogen mass flow are determined in the MFA and EFA, and can be easily monetised when linked to a certain price parameter/pattern. Excel has been chosen as an application for the MEFA in order to ensure that all calculations and the parameters on which they are based can be easily traced. How this has been implemented in the model structure is shown in Figure 21 - Set up of the MS-Excel MEFA model.

10 A complete MEFA can also include a life cycle analysis. However, the large amount of data that would be involved, its availability and the resource and time intensity required exceeds the boundaries of this study and has therefore not been taken into account.

Figure 21 - Set up of the MS-Excel MEFA model



4.2 Future electricity and hydrogen market prices

Future electricity and hydrogen market prices play an important role in the outcome of the business case for the multifunctional offshore island. In the next paragraphs we describe how these prices are modelled for the techno-economic assessment of the island.

4.2.1 Electricity market prices - the PowerFlex Model

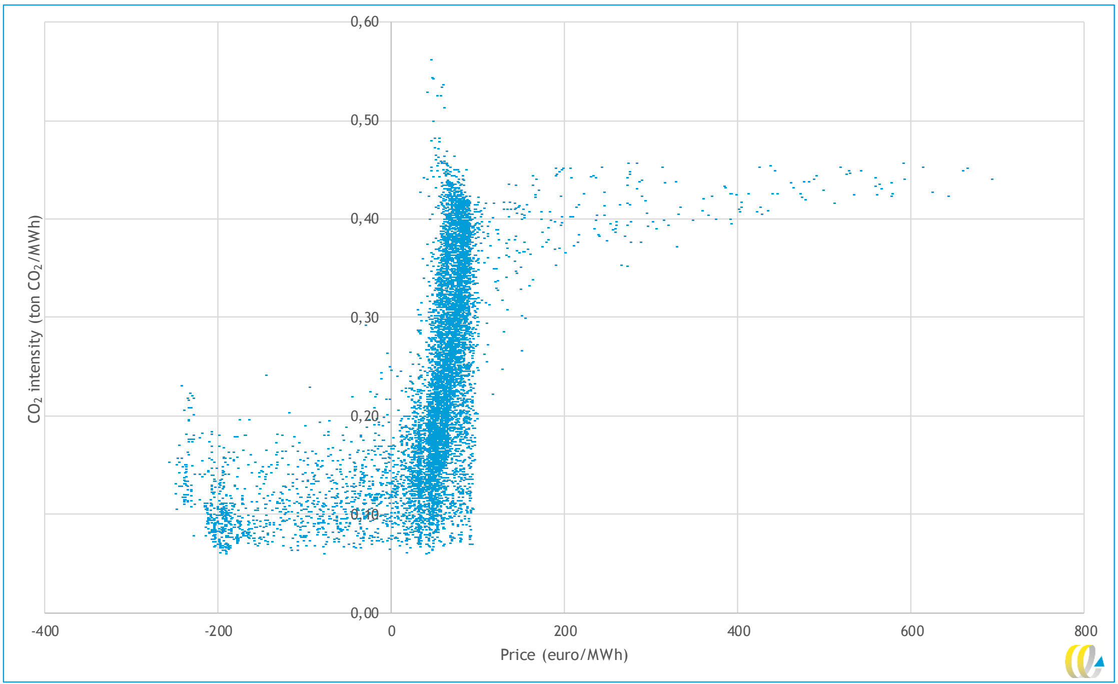
Future electricity market prices are modelled using the PowerFlex model developed by CE Delft. The model simulates the dynamic operation of the electricity system via the unit commitment and dispatch optimisation of power plants, storage units, and power-to-heat installations. The assets are dispatched to achieve lowest overall system costs, taking into account relevant constraints. Simulations are carried out for the Netherlands and Germany as model core regions for the years 2029 and 2050. The year 2029 has been chosen as a reference year since it expected to be is the last year in which coal-fired power-plants are not entirely phased out yet. In fact, this is one year before all Dutch Climate Agreement policies are fully implemented. In the years from 2030 until 2050 all fossil power plants are assumed to be phased out which is reflected in the price difference between both modelled years (2029 and 2050). In 2050, the functionality of back-up power is expected to be fulfilled by hydrogen fuelled power plants. Appendix E provides a detailed description of the implementation of different scenarios for this study in the PowerFlex model.

A number of modifications to the standard PowerFlex simulation tool are required to make it applicable to the scenarios and goals in this study:

- First, the time series for offshore wind power generation have been adjusted to include wind speeds provided by KNMI for the IJmuiden Ver wind area (Koninklijk Nederlands Meteorologisch Instituut, 2020). The profile of the year 2017 is used. The wind profile is adjusted to reflect the latest technological improvements in wind turbine technology, based on the Haliade-X turbine of General Electric. The wind generation profile thus includes the assumption of a maximum wind park power generation of some 95.4% (taking into account wake losses and internal wind park cable losses based on an available wind duration profile; see also (Jepma & van Schot, 2017)).
- Second, negative prices have been adapted manually. According to the original modelling outcomes, during approximately 2,000 hours per year the renewable production exceeds the demand from the Netherlands and Germany. At times of electricity surplus, the PowerFlex model yields negative prices. However, it can be expected that such negative prices will not occur in reality as demand will adapt to generation and/or generation will be curtailed.
- Third, this study is concerned with the generation of green hydrogen, which is produced using renewable electricity. In 2050 all generation is expected to be renewable. In 2029, part of the electricity on the grid comes from fossil resources. A study conducted by CE Delft (CE Delft, 2019) shows that for mixed electricity generation resources, the average CO_2-content of the electricity increases with price. With rising prices, the share of renewable electricity production is smaller. For this reason, in our modelling, the operations of the P2G operator are limited to times with electricity prices below 100 €/MWh ()[11].

[11] Note that this production cap only exist for 2029. Hydrogen production becomes less attractive the more electricity prices increase since the marginal cost of hydrogen production may outweigh increasingly the marginal revenues. The impact of this cap is rather marginal as the electricity prices only exceed 100 €/MWh in less than 5% of the time.

Figure 22 - Relation of CO_2 intensity and Dutch electricity prices



Source: (based on (CE Delft, 2019)).

The chosen wind duration profiles (Chapter 4.4.2) of the wind park and the electricity prices from the PowerFlex model have been verified to compatible. High wind speeds and resulting high hydrogen production only marginally correlates with extreme electricity prices. A correlation analysis shows that there is a correlation coefficient of about -0.2, which indicates very little correlation between both factors. Including large numbers of future wind farms may change this outcome. In this analysis, power prices are included as independent from wind speed.

4.2.2 Electricity price assumptions for the techno-economic model

Table 4 provides a summary of the mean day ahead electricity prices applied for each scenario. For the cash flow time series a linear relation between prices in 2029 and 2050 has been assumed.

Table 4 - Mean electricity prices per scenario. The price ranges for the year 2050, in which hydrogen fuelled power plants play a role, are based on hydrogen market prices of: 1.5 €/kg (low); 3.0 €/kg(reference); 5.0 €/kg (high)[12]

	Mean 2029 in €/MWh	Mean 2050 in €/MWh	Relevant market price for the power-to-gas facility
Onshore Hydrogen	59.06	Low price: 60.05 Reference: 115 High price: 210.07	Simulated market electricity price (for share bought from the grid)
Onshore Hybrid	58.28		Simulated market electricity price (for all electricity)

12 The price differences between the scenarios show the limited impact of the P2G plant on the whole electricity system.

	Mean 2029 in €/MWh	Mean 2050 in €/MWh	Relevant market price for the power-to-gas facility
Island Hybrid - Maximal Cable	58.28		Simulated market electricity price (for all electricity)
Island Hybrid - Optimal Cable	57.74		Simulated market electricity price (for all electricity)

In addition to the day ahead prices resulting from the PowerFlex model, which apply typically to market participants connected to the onshore grid, we also account for bilateral agreements between power-to-gas and wind park operators. Both trading schemes, bilateral trading and day ahead spot trading are applied in the model as follows:

- For scenarios where there is a **only a connection between the wind farm and the power-to-gas facility** (scenarios Onshore hydrogen and Island hydrogen), we assume that all electricity from the wind farm is sold using bilateral contracts between the P2G and the wind park operator. We assume a price based on an average levelised cost of electricity (LCOE) for offshore wind of **40 €/MWh**[13]. A sensitivity analysis is performed to identify the relevance of bilateral contract prices on the overall business case (see Chapter 5).
- At times when the **wind park is not deployed at full capacity** and when there is a **connection between P2G plant and the onshore transmission grid** (all scenarios except of Island hydrogen), the operator decides whether or not to buy extra electricity from the market based on day-ahead market prices. This electricity is priced variably depending on the day ahead market price. The electricity bought from the wind farm is still priced based on a bilateral contract price of 40 €/MWh.
- Whenever **both wind park and the power-to-gas facility operators have access to the onshore transmission grid**, the electricity sourced from the wind farm and the onshore grid is priced according to the day ahead price pattern (Onshore hybrid and Island hybrid scenarios).
- A separate approach is developed for a **corner case in Scenario 4 - offshore hybrid with optimal cable**. For this scenario, the amount of energy converted into hydrogen (x%), is determined using a dedicated model. The model calculates costs and revenues from all possible combinations of x, i.e. ranging from 0% (indicating no power-to-gas facility is installed and all wind power will be transmitted via HVDC) to 100% (indicating no HVDC is installed and all wind energy will be converted into hydrogen), see next sections and Appendix F.3 for more details. This approach leads to a corner case where the wind park operator cannot distribute the full amount of electricity to the consumer (P2G plant or onshore transmission grid). This can be the case when the electric infrastructure is not dimensioned to the maximum capacity of the wind park as a result of the optimisation, leading to a situation where: (1) the wind park generates more power than the capacity of the offshore electric connection (x> 0%); (2) day ahead prices are too high for economic production of hydrogen and therefore the P2G operator has no interest to buy electricity. As a result, only a share of the power could be transported to the onshore grid and parts of the generated power ending up curtailed. In that case we assume that both operators can find a compromise for the benefit of the total system costs. A compensation of **40 €/MWh** is paid by the P2G plant to cover the

[13] The number is based on the combination of an internal analysis by CE Delft, stimulation measures by the Netherlands Enterprise Agency to realise a cost reduction for offshore wind towards 30 €/MWh to 40 €/MWh, and WindEurope estimates of some 50 €/MWh for the IJmuiden Ver region (this value includes grid connection, which we have treated separately) (WindEurope, 2019).

wind park operator’s generation costs for electricity that would otherwise need to be curtailed but is now instead converted into hydrogen.

The trading schemes are summarised in Table 5.

Table 5 - Application of electricity prices to system configuration scenarios

System configuration scenarios	Electricity source	Electricity pricing mechanism	Remark
1- Onshore hydrogen	Wind park	Bilateral trading	Wind park is only connected to P2G
	Onshore grid	DA-spot trading	Grid electricity just complementary to wind park electricity
2- Island hydrogen	Wind park	Bilateral trading	Wind park is only connected to Island
3- Onshore hybrid	Wind park	DA-spot trading	Both operators are connected to the onshore grid
	Onshore grid	DA-spot trading	
4.1 - Island hybrid Maximal cable	Wind park	DA-spot trading	Both operators are connected to the onshore grid
	Onshore grid	DA-spot trading	
4.2 - Island hybrid Optimal cable	Wind park	DA-spot trading	Both operators are connected to the onshore grid
	Wind park	Bilateral trading	Applied to energy potentially curtailed.
	Onshore grid	DA-spot trading	Both operators are connected to the onshore grid

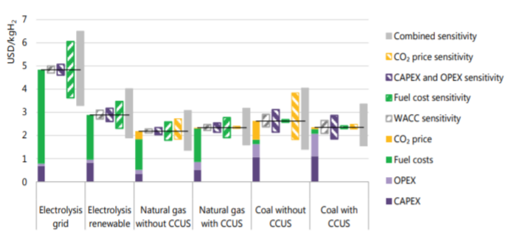
4.2.3 Hydrogen market prices

Chapter 3.2.2. provided a general overview of the hydrogen market potential in the Netherlands. Currently production mostly takes place onsite by local autothermal reforming (ATR) and steam methane reforming (SMR) units, as a by-product of another production process. Therefore, only little information about hydrogen prices and price formation is publicly and transparently available. The CertifHy study (Fraile, et al., 2015) finds as well that most hydrogen transactions are based on bilateral agreements between two parties and thus, prices may differ significantly due to information asymmetry of location, physical state of hydrogen (in most cases gaseous or liquid) and purity level. To break down the complexity of hydrogen market prices in our model we consider two main approaches: comparative production price approach and the comparative market prices approach.

Comparative production price approach

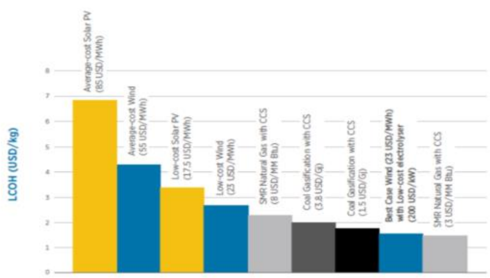
In the short term, the production of green hydrogen competes with the traditional hydrogen productions methods from natural gas and coal without CCS. A report published by the IEA (IEA, 2019) gives a good overview about prices of hydrogen production for different technologies (Figure 23a). According to the report, production costs of grey hydrogen are in the order of 1.5 €/kg, though, the inclusion of CO_2 taxes (e.g. 35 €/ton), increase the average production cost to some 1.9 €/kg.[14] On the mid- to long-term, it seems likely that hydrogen production from offshore wind competes with other options for green hydrogen production or blue hydrogen production. The ballpark figure for blue hydrogen production from natural gas is in the order of 1.4 €/kg to 2.1 €/kg (IEA, 2019) (IRENA, 2019), though, this figure strongly depends on the actual distance to a CO_2 storage site and the market price development for natural gas. The price for green hydrogen from renewable electricity is expected to be 2.6 €/kg, with electricity prices of some 35 €/MWh and an utilisation factor of 46% (IEA, 2019). Comparing this to current price figures of renewable hydrogen production, we conclude that a large decrease in technology and electricity costs and/or the implementation of supportive policies is required for market competitive hydrogen production via “wind/sun electrolysis”. A similar LCOH comparison can be found in a study performed by the International Renewable Energy Agency (IRENA) (IRENA, 2019). However, here the production from hydrogen via electrolysis is differentiated between hydrogen from solar-PV and wind as shown in Figure 23b.

Figure 23a - Hydrogen production costs



Source: (IEA, 2019).

Figure 23b - Hydrogen production costs



Source: (IRENA, 2019, p. 28).

By adding additional cost elements that typically apply outside of the business case’s boundaries such as purification, onsite compression and storage, operator margins, etc., one could approximately estimate the market value. Nevertheless, specifying an accurate additional cost element requires extensive research given that the support of this assumption is very much case dependent, in particular due to required information about succeeding processes, i.e. hydrogen distribution and varying and non-transparent margin expectations of respective operators, industry, etc.

Comparative market prices approach

A different approach is to use market prices from different demand sectors for comparison. Industrial applications such as metal processing, refineries, and the chemical industry have long been large consumers of grey hydrogen, but it is uncertain whether or not green hydrogen can compete with grey or even blue hydrogen as a feedstock in these industries. Yet, one should take into account that hydrogen quality plays an important role within industry (e.g. methanol and ammonia) production processes. To which extent quality improving measures and processes are included in the conventional cost price calculations is not clear, though the inclusion of purification costs have a direct impact on the cost of production of hydrogen to

[14] Cost prices are originally expressed in USD/kg. For comparability reasons we applied a conversion factor of 1 USD to 1.12 EUR (2019) to the figures mentioned in the IEA report.

meet certain quality expectations. Figure 24 provides an overview of purity levels for gaseous hydrogen demand in various industry segments. In addition to this, the commercial sale of the hydrogen consists of commodities with varying levels of impurities[15]. The advantage of electrolyser technology is that these technologies are able to deliver hydrogen gas at 99.9998% purity level[16]. This is in strong contrast to the hydrogen purity in the ATR outlet stream, which is expected to be in the order of 95.5% for an ATR plant (H-vision, 2019).

Figure 24 - Quality levels of hydrogen

Quality Verification Level	Typical Uses	Hydrogen purity
B	General industrial applications	99.95%
D	Hydrogenation and water chemistry	99.99%
F	Instrumentation and Propellant	99.995%
L	Semiconductor and specialty applications	99.999%

Source: (retrieved from (Fraile, et al., 2015)**).**

Consequently, when considering a comparative market price for green hydrogen, it is one option to refer to prices paid by the various industry sectors where most hydrogen production is placed directly on the production site or where the hydrogen is sold within a captive market (Fraile, et al., 2015). For a substitution of grey or even blue hydrogen via hydrogen produced from renewable electricity this is a fairly high market barrier since in the worst case, green hydrogen would need to compete with cost prices in the order of 1.5 €/kg to 1.9 €/kg (IEA, 2019). Though, the costs for cleaning the hydrogen (e.g. with a pressure swing adsorption (PSA) system) are not included in the hydrogen cost price.

Hydrogen can also be used as a fuel source in the mobility sector or by decentralised small industrial consumers. In contrast to the industry sector, the transport sector has higher hydrogen purity quality standards which are specified in ISO 14687 where a level of 99.995% purity is mentioned (Fraile, et al., 2015). In addition, the hydrogen needs to be compressed to some 700/350 bars. The costs for purifying, compressing and distributing the hydrogen comes typically at a higher costs. One may argue that in this regard, sectors requiring higher quality hydrogen are also willing to pay a higher price. Next to the argument of different hydrogen characteristics per sector, the willingness of customers to pay up to a certain price can influence the achieved market price significantly. Some discussions lead to prices in the range of 6-10 €/kg considering the willingness to pay of consumers given current prices of gasoline at the pump (Jepma, et al., 2018), (North Sea Energy, 2020c).
According to the CertifHy study (Fraile, et al., 2015) current prices paid for hydrogen already vary significantly between 10-60 €/kg but expect that retail prices are going to decrease to 5-7 €/kg by 2030.

Based on the considerations above, this study assumes hydrogen prices based on two comparative market prices. What needs to be pointed out and reflected by the chosen market prices is the crucial point of the currently non-transparent and captive market for hydrogen and the inherent uncertainty. To reflect on this uncertainty, we calculate first with a 1.5 €/kg conservative case where green hydrogen production would have to compete with

15 HiQ Specialty Gases Finder : Hydrogen H2

16 Nelhydrogen : M series Proton PEM Electrolyser

bulk onsite hydrogen production. This price is in the order of magnitude of the lowest LCOH technology represented in (IEA, 2019), (IRENA, 2019). Second, we compare the conservative case with an arbitrary 6.0 €/kg high market price case based on the upper limit pointed out in the description above. [17]

4.2.4 Energy management strategy per scenario

Four scenarios have been determined that shall be analysed within from a techno-economic point of view. Amongst these scenarios there are two reference scenarios that reflect on a 'business-as-usual' situation where P2G takes place onshore (Scenario 1 and 3).
In comparison, Scenario 2 and 4 describe the Island concept in various ways.

Scenario 1-Onshore Hydrogen

In this scenario, we look into an onshore P2G plant that is directly connected via a 525 kV DC cable and an offshore substation on a platform to the wind park. The direct connection to the P2G plant implies that the wind farm operator cannot sell its generated electricity to the market. Although, the wind park operator has no connection to the electricity market, there is an low-voltage electricity connection between the P2G plant to the onshore electricity grid. What is essential in this scenario is that we assume that all electricity coming from the wind park is prioritized over electricity coming from the market and valued based on a fixed contracted price between P2G and wind park operator. The electricity price is assumed to be 40 €/MWh, based on an average LCOE for offshore wind (incl. grid connection) of 50 €/MWh that relates to the upper limit for the 'very low' LCOE range which can be expected to be valid for wind parks built in the IJmuiden Ver region (WindEurope, 2019) minus the levelised costs of the offshore electric grid (incl. onshore and offshore substation & HVDC cable) estimated to be some 10 €/MWh[18].
Due to the additional grid connection between the P2G plant and the onshore electricity grid, the P2G facility has also the opportunity to buy electricity from the market. Once the electrolyser capacity is not fully used in times of little wind, we assume the operator decides based on DA-market price profile whether to buy extra electricity to keep the electrolyser on full capacity. The actual price based on which the P2G operator decides to buy electricity is called the electricity cut-in price. The cut-in is derived from the marginal production costs and the specific hydrogen price:

Equation 1: Electricity cut-in price

$$p_{e,cut-in}[\frac{EUR}{MWh}] = \frac{p_{hydrogen}[\frac{EUR}{kg}] * 1000}{\eta_{electrolysis}\left[\frac{kWh}{kg}\right]}$$

[17] For the mobility sector, prices may even exceed the named ranges. Some discussions lead to prices in the range of 10 €/kg considering the willingness to pay of consumers given current prices of gasoline at the pump. However, this price can be expected to include the costs for infrastructure that is required to deliver the fuel from the production source to the end use. Since our system boundaries do not include the whole value chain of hydrogen production and distribution we decided to set a maximum at 6 €/kg.

[18] The RVO stimulation policy is focused on realising cost reductions for offshore wind toward 30 €/MWh to 40 €/MWh (RVO, 2019). The 10 €/MWh investment for the HVDC electric equipment are based on an internal TNO tool (see also Section 4.3 (TNO, 2019a)).

with $p_{hydrogen}$ = specific hydrogen revenue

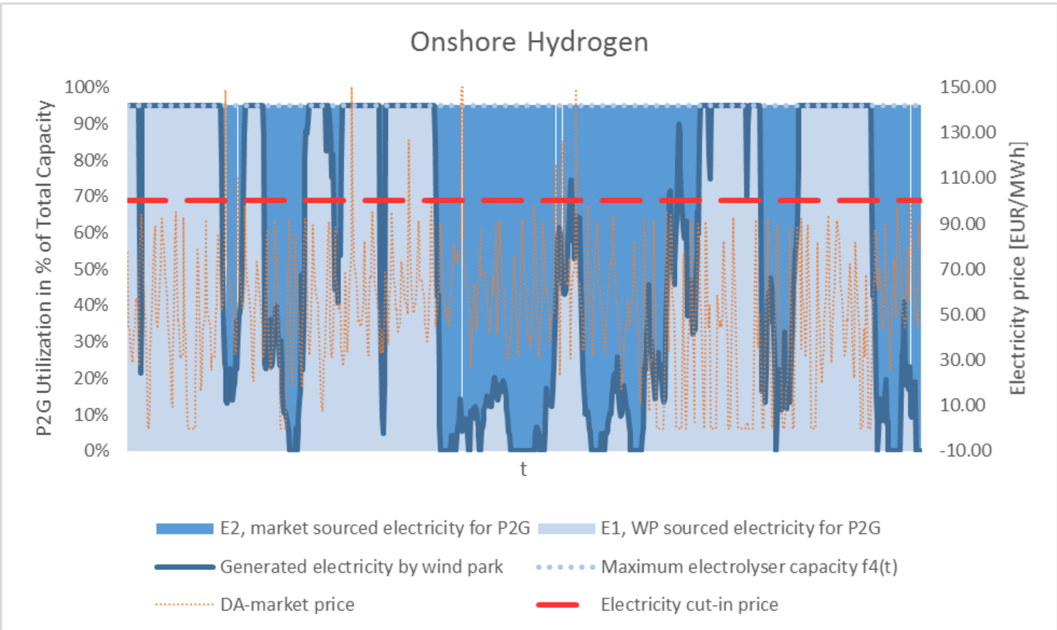
Given an electrolyser efficiency of 52.48 kWh/kg and a specific hydrogen price of either (a) 1.50 €/kg or (b) 6.00 €/kg, the operator would consider buying electricity when the DA-market price is below (a) 28.58 €/MWh or (b) 114.34 €/MWh respectively.
To determine the average annual electricity price for market electricity we use the weighted average electricity price:

Equation 2: Average price paid for grid electricity (Scenario 1)

$$P_{weighted\ average}\left[\frac{EUR}{MWh}\right] = \frac{\sum_{i=0}^{k=n} P(t = i \dots k) * Q_e(t = i \dots k)}{\sum_{i=0}^{k=n} Q_e(t = i \dots k)}$$

With P(t) = market price at time t, and Q_e(t) electricity bought at time t

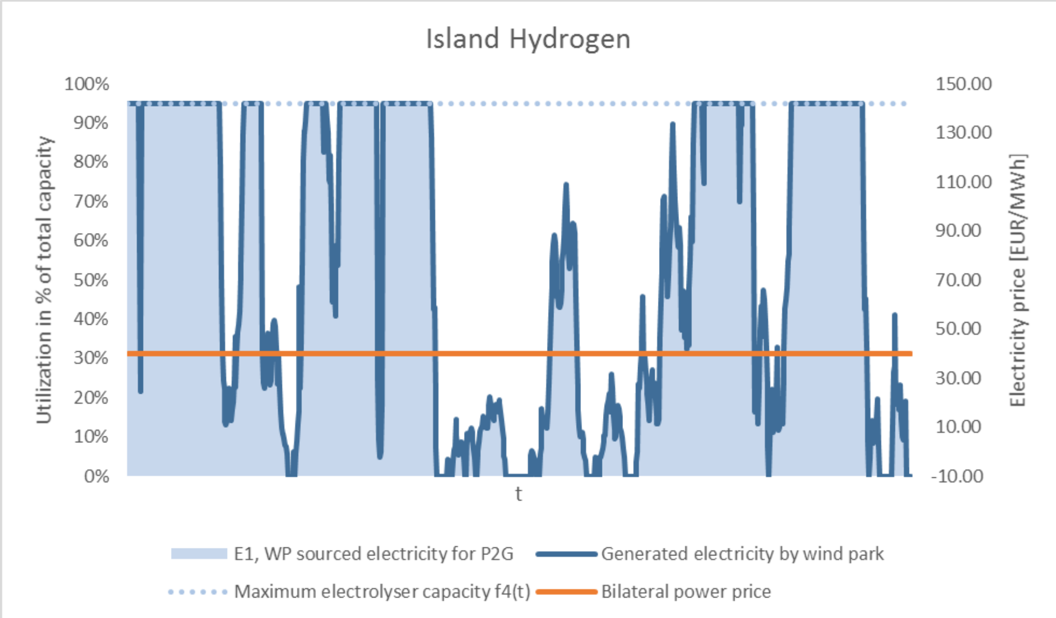
Figure 25 - Visualisation of system operation scenario Onshore Hydrogen (snapshot 2029, hydrogen market price=6.00 €/kg)



Scenario 2 - Island Hydrogen

Within this scenario all electricity generated by the wind park is converted to hydrogen offshore and transported via pipelines to the mainland. There is no connection to the onshore electricity grid, so, in times of insufficient wind the P2G plant may stand idle. Since the wind park is only connected to the Island and not to the mainland, we assume electricity used for electrolysis is priced with a fixed price of 40 €/MWh based on bilateral agreement between the wind park and P2G operator.

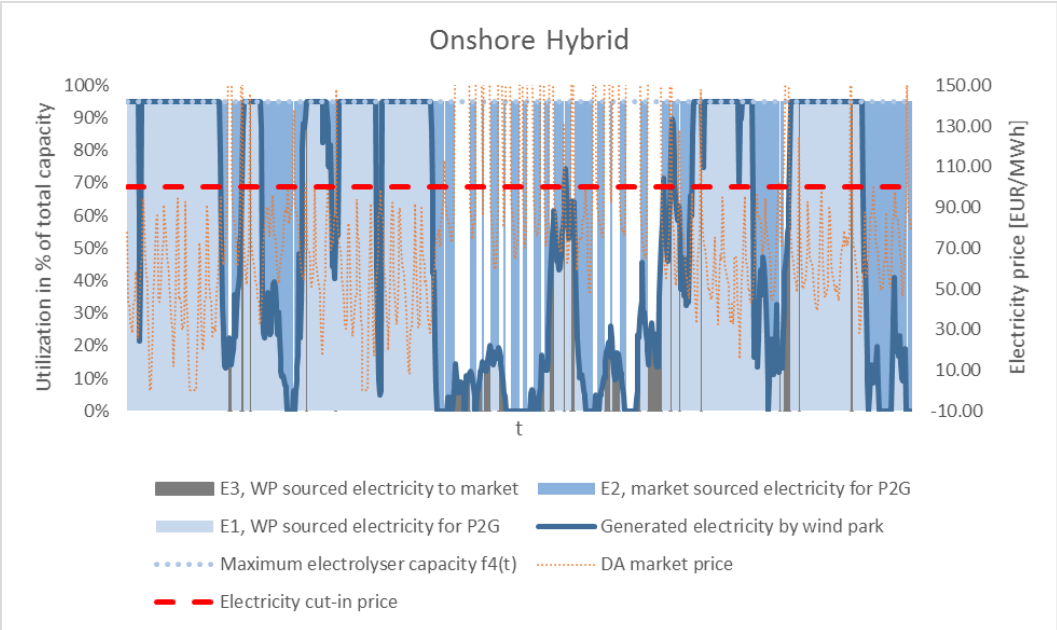
Figure 26 - Visualisation of system operation in scenario Island Hydrogen (snapshot 2029)



Scenario 3 - Onshore Hybrid

In Scenario 3 the power-to-gas facility is placed onshore, where it has access to both green electricity from the wind park and electricity from the grid. In contrast to Scenario 1, the wind farm operator does have the choice to sell its generated electricity either to the power-to-gas facility operator or the market. This is why we assume that the electricity price paid is not fixed but depends on fully on DA-market prices. Results are shown in Figure 27.

Figure 27 - Visualisation of system operation in scenario Onshore Hybrid (snapshot 2029, hydrogen market price=6.0 €/kg)



Scenario 4 - Offshore hybrid scenario

Scenario 4 looks into an offshore hybrid Island case where both, P2G and electric power conversion for electric transmission purpose take place next to each other. In this scenario we simulate what **share of energy** [%] will be directed to the mainland as electrons and what share undergoes the conversion process to hydrogen. At the same time, we investigate whether there are benefits in optimizing the installed **capacity** [GW] of power conversion and P2G equipment given certain market conditions i.e. an optimisation of hydrogen production based on a fluctuating electricity price and given a certain product value. Two sub-scenarios have been defined in order to see whether there is a benefit in an optimisation (see also Section 3.3):

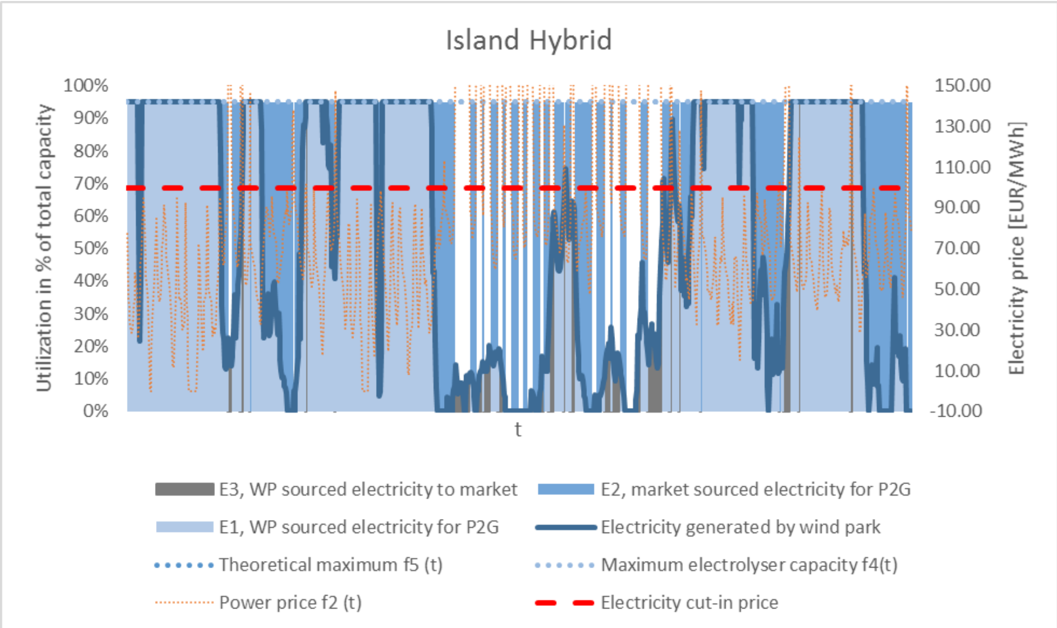
a Scenario offshore hybrid-Optimal Cable:
The system capacity of P2G and electric power conversion is optimized so that always the energy is partly distributed as hydrogen and partly as an electron due to long-term infrastructure capacity optimization.

b Scenario offshore hybrid-Maximal Cable:
The electric and hydrogen infrastructure is dimensioned to the maximum capacity of the wind park. Thus, the decision to produce hydrogen or not is solely based on market prices. Infrastructure is not a constraint in this case.

For the first sub-scenario we follow an iterative approach, developed by HAN, to determine the capital investments which once taken are a mostly irreversible and have a fixed impact on the long-term business case. In that regard, we determine a share of **capacity** allocated to the electric system allowing for electrons to be transported to the onshore grid and the rest being allocated to the P2G system. This affects the size of equipment e.g. the converter and cable capacity and the power-to-gas facility capacity. Second, it is of the island operator's interest how the system could operate economically optimal on a short-term. For this consideration it is important to keep in mind that investments have already been done and the equipment is installed and in place. Therefore, we determine the amount of electricity that is available to produce hydrogen given the previously determined capacity constraints.

The latter sub-scenario is characterised by a full infrastructure for hydrogen and electricity (Figure 28). This system is compared to the other two cases the most flexible system and no curtailment needs to take place due to infrastructure congestion. On the other side, the flexibility comes at a high cost. Total infrastructure investments are in this case the largest of all cases. Whether the benefit of full flexibility outweighs the disadvantage of large capital expenditures is analysed in the results section.

Figure 28 - Use of electricity in scenario Island Hybrid with a hydrogen market price=6.00 €/kg and electricity cut-in price=114.34 €/MWh (snapshot 2029)



4.3 Assumptions related to system components

Our assumptions regarding relevant system components are implemented in the model's asset database which contains the most important specifications of equipment that is related to the electricity and hydrogen process flows.
All scenarios consider a **project horizon of 2026-2050**. As a general rule, we differ between years where construction take place (2026-2029)[19] and the fully operational years (2030-2050). Consequently, we split the CAPEX of all equipment evenly during the construction period where also no OPEX besides the general and administrative expenses (G&A) is applied but also neither hydrogen is produced nor electricity transmitted and sold. Revenues and the remaining OPEX components as well as reinvestments (e.g. electrolyser stacks) are taken into account for the period of 2030-2050.

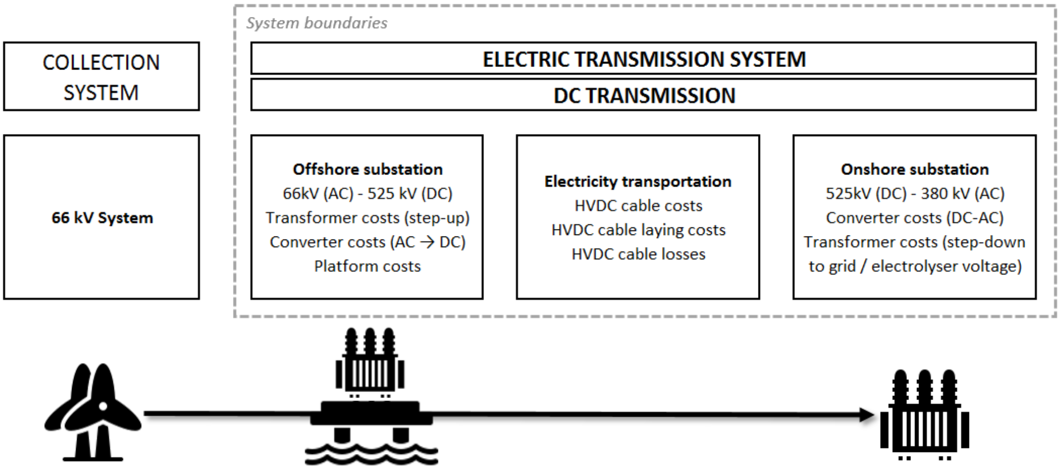
[19] According to the results of WP 1, a construction period of 3-5 years for an island is plausible.

For our business case analysis, we use estimates provided by internal project partners and analyse literature where needed. This can potentially lead to different definitions of what has been assumed to be included in the CAPEX figures next to the pure material costs and what has not been considered (civil work, project management, R&D, contingency, etc.).
In general, we assume the CAPEX's equal the purchase price including the material and required labour to install the equipment before taxes unless specified differently.
The common OPEX figures are assumed to include expenses that are directly related to operate the equipment including labour and maintenance but excluding energy costs which are accounted for separately. Expenses that are related to operate the company such as G&A are also accounted for separately. Process efficiencies and equipment footprint mentioned are assumed to include all process related equipment (e.g. electrolysis → electrolyser & balance of plant).

4.3.1 Power conversion assets and electric transmission

In our business case analysis we take into account the main power conversion equipment such as transformers, converters, an offshore substation[20], the respective cabling for the electric transport to the mainland and an onshore substation ().

Figure 29 - Electric transmission system and components [21]



In our study we limit the consideration of possible electric systems to a 525 kV HVDC system. With this boundary we follow the existing plans of TenneT for the IJmuiden Ver region (TenneT Holding B.V., 2020). One relevant factor of the electric system are losses that can occur when e.g. electricity needs to be transformed from one voltage level to another, when AC/DC conversion is required and when electricity is transported via cables to shore.
We base our assumptions related to the power system efficiencies on a report of Rodrigues (Rodrigues, 2016) and conclude with efficiencies of power conversion equipment as mentioned in Table 6:

[20] Depending on the scenario the offshore substation is located either on a platform or on the island.
[21] Icons retrieved from: Icons8

Table 6 - Power conversion equipment efficiencies

Process parameter	Unit	Value
Transformer efficiency	[%]	99%
Converter efficiency	[%]	99%
HVAC cable loss connection transformer-converter	[%]	0.2%

Next to the power conversion equipment, we include HVDC cable losses. In general one can state that cable losses of a DC cable are way less affected with increasing distance compared to AC cable losses. This is also shown in the previously mentioned report of Rodrigues where cable losses for differing distances of a particular scenario are compared (Rodrigues, 2016, p. 146). As a ballpark estimate we assume a linear relation between HVDC losses and distance:

$$Cable\ losses = 6 \times 10^{-5} \times L_{cable} - 0.0002$$

Here, L_{cable} equals the linear distance multiplied by a cable length factor of 1.3 to account for cable routing. The required capital expenditures for HVDC electric equipment are calculated based on an internal TNO tool (TNO, 2019a).

4.3.2 Offshore island cost estimate

The construction costs are estimated for the three island sizes as reported in Section 3.2. The costs are calculated with an island concept model including costing tools developed by RHDHV for offshore energy island. The model determines an island layout and calculates material volumes for a given functionality of the island and specified environmental conditions. Construction costs are calculated from material volume and unit costs. Unit costs are taken from our own database in which costs for several projects in and outside the Netherlands are collected. The model has been validated with cost estimates received from Contractors for offshore island projects. Unfortunately, no actual project costs are yet available to validate the model with.
Costs are on price level 2019 and is given construction costs for the island. No VAT or other taxes are included and no costs from project owner side are included. The accuracy of the cost estimate is estimated at -20/+40%.

Most important cost items are unit rates for sand and costs for revetments and breakwater. For the location as considered in this study these costs are:

- all-in rate for supplying sand on the island: € 12/m^3
- revetment facing N, W and SW: € 230,000/m’
- revetment and breakwater facing E: € 150,000/’

For the three island sizes costs as estimated with the model are given in Table 7.

Table 7 - Estimated construction costs

	Area (ha)				Costs	
	Land	Quay	Port basin	Total	Island 10^6 Euro	Land cost euro/m^2
Standalone Hydrogen island	17	2	6	25	570	3,000
Combined hydrogen and HVDC island	27	3	7	37	720	2,400
Multipurpose island	85	9	18	114	1,370	1,425

As can been seen the cost per m^2 area will quickly reduce if a larger island is considered. Developing an offshore island for multipurpose use is therefore recommended pure from island construction point of view.

Construction time for the island is estimate on 2 to 3 years for the small Island (25 ha) to 3 to 5 years for the larger multipurpose island (114 ha).

Given the scenario description, we focus on the multi-functional island concept for the offshore Scenarios 2 and 4. According to the outcome a multipurpose island has sufficient area to host the offshore power conversion and the power-to-gas function next to other essential parts such as the quay, helideck, etc. In fact, some 11 ha are required for P2G activities and 12 ha for the power conversion activities. The island costs are assumed to be allocated accordingly so based on the area required for both activities plus a surplus of 5% to account for roads, accommodation and other potential auxiliary services. The corresponding equations for the distribution of costs is therefore shared based on the specific used are per operator as part of the total island land size (some 96 ha excluding 18 ha for port basin):

$$CAPEX_{Island,P2G} = \frac{(11ha + 5\% \times 96ha)}{96\ ha} \times \frac{1{,}370\ MEUR}{2\ GW} = 113 MEUR/GW$$

$$CAPEX_{Island,OTSO} = \frac{(12ha + 5\% \times 96ha)}{96\ ha} \times \frac{1{,}370\ MEUR}{2\ GW} = 120 MEUR/GW$$

4.3.3 Electrolysis

In this study we consider hydrogen production from wind electricity via water electrolysis. There are different technologies available to perform the electrolysis out of which one technology is selected based on evaluating a set of criteria:

- **Maturity** — Description of the technology’s market maturity, relative costs and what future developments can be expected.
- **Partial-load performance and Dynamics**- Electricity generated by the offshore wind farms is highly intermittent. Thus, it is crucial how technology performs on partial load and how rapidly it can react to load changes.
- **Operational performance —** Efficiency and pressure of the electrolyser unit.
- **Equipment lifetime.**

Generally, we focus the comparison on Proton Exchange Membrane (PEM) and Alkaline (ALK) electrolysis since those are the most mature technologies. Solid oxide electrolyser cells (SOEC) may be a viable option in future, however, there are no commercial appliances at large capacities currently available. In addition, it is likely that SOEC electrolysers are more sensitive to partial load performance as well as intermittent power input which makes this technology less attractive in our case.
Table 8 shows a brief comparison of the remaining technologies. Given the displayed advantages, we reason that PEM electrolysers are most suitable to the conditions of offshore hydrogen production on the energy island. Besides, particular advantages like the higher output pressure could even substitute the offshore compression process.

Table 8 - Comparison of PEM and ALK electrolysis based on (Xiang, et al., 2016), (Smolinka, et al., 2011), (IRENA, 2018), (Noack, et al., 2014)[22]

PEM		ALK	
Advantages	Disadvantages	Advantages	Disadvantages
Pressurized product	Close to technology maturity	Most mature technology	Low dynamic operation
Large improvements expected in future (durability and costs)	Higher relative costs compared to ALK	Lowest cost levels at the moment	Low pressurized product
Very good partial load range and high reactivity	Less durability	Long durability	Limited load range (min. ~20-30%)
			Poor efficiency and lifetime with partial loads
			Little technology improvement potential

As the reaction requires just (demi) water and electricity as reactants this is rather simple. However, due to the high sensitivity of electrolyser cells to any impurities water needs to be treated to meet the high-quality demands. For that reason, another water treatment step is implemented in the model. More information about the respective process can be retrieved from (Jepma & van Schot, 2017). The main asset data is related to the electrolysis and water treatment unit specifications and the respective cost figures jointly shown in Table 9.

Table 9 - Electrolysis parameters

Process parameter	Unit	Value	Source
Electrolysis			
Electrolyser efficiency	kWh_{el}/kg hydrogen	52.48	NEL hydrogen, Hydrogenics, Siemens[23]
Outlet pressure electrolyser	bar	30.00	(Thomas, et al., 2016)
Fresh water demand electrolyser	l/Nm^3 hydrogen	1.30	(Thomas, et al., 2016)
Economic lifetime electrolysis	[y]	20	Assumption
Lifetime stack	[h]	50,000.00	(Thomas, et al., 2016)
Capex share stack	[%]	50%	(Thomas, et al., 2016)
Relative CAPEX electrolyser	EUR / kW	700.00	(Thomas, et al., 2016) in connection with (FCH JU, 2014) - System CAPEX in 2030
Contingency	[%]	20%	Assumption
Relative OPEX electrolyser	[%] of Capex	4%	Assumption
Scale factor electrolysis, $f_{electrolysis}$	[-]	0.80	Assumption

22 What has not been mentioned in the table above is the potential of PEM electrolysers to produce at higher loads than their rated power for short periods:
- Silyzer 300 for 10-20 minutes up to 160% of rated power;
- Noack et al. (2014) reports two scenarios:
  - a low risk scenario: 5 MW system → at 150 % nominal load for 30 minutes;
  - a high risk scenario: 100 MW system → 200 % nominal load for 30 minutes in 2029.

We decided not to model these effects even though they may affect the business case positively due to peaks of wind production which can be converted even with lower electrolyser capacities. On the other side, one can imagine that exceeding the rated power of the equipment influences the equipment lifetime. Due to a lack of available data, we have not taken this electrolyser criteria into account.

23 Average value of all sources (NEL M-series 3, Hydrogenics HySTAT, Siemens Silyzer 300).

Process parameter	Unit	Value	Source
Reference capacity electrolysis @ 700,000 EUR / MW	[MW]	15.288	(Thomas, et al., 2016)
Water treatment			
Recovery rate	%	80%	Lenntech
Relative power requirement water treatment	kW/(litre/hour)	0.004	
Relative area water treatment	$m^2/(30\ m^3/h)$	133.80	
Relative CAPEX water treatment	EUR/(l/h)	49.92	
Relative OPEX water treatment	% of Capex	4%	Assumption
Economic lifetime water treatment unit	[y]	20	Assumption

4.3.4 Compression of hydrogen

Compression of hydrogen is usually required in order to transport the volumes over (large) distances to the onshore point of connection. Larger pressures result in higher volumetric energy contents that can be delivered during a certain period, however, this also impacts the design criteria of the chosen pipeline system and generally increases its costs. On this topic, Intecsea has conducted a hydraulic analysis for the offshore P2G scenarios on the hydrogen flow. The outcome shows, that given a 30-35 bar electrolyser output pressure, an average hydrogen flow of about 260 Nm^3/h and a peak flow of about 410 Nm^3/h, the calculated pressure drop does not require additional offshore compression for the purpose of transporting the hydrogen to onshore. For more details we refer to Section 4.3.5.
On the other hand, we decided to include an onshore compression station in order to be able to compare the end product along the various scenarios in terms of pressure level. As a reference pressure level, we refer to Gasunie's plans of a hydrogen backbone infrastructure (N.V. Nederlandse Gasunie, n.d.). According to Gasunie (Duym (Gasunie), 2020), two pressure regimes are investigated: one for 30/50 bar and the other one operating at 10/30 bar. As a reference pressure we take the maximum of 50 bar.
There are different types of compressors which can mainly be divided in dynamic compressors (axial & centrifugal compressors) and positive displacement compressors (reciprocating & rotary compressors). Each type has its limitations regarding pressure ranges and fluid volumes and so for different natural gas transportation cases, different compressors may be selected. Due to the origin of this study, the detailed analysis of compressor systems has not been further analysed, as this will take place at a later stage of a project (e.g. design/engineering phase). The assumptions related to the CAPEX of a full onshore compressor station are based on available information of the BBL pipeline project, literature related to the compression unit CAPEX (André et al, 2014) and a general estimate provided by Intecsea and are listed in the table below.

Table 10 - Onshore compression station CAPEX components

Process parameter	Unit	Value
Permits and Engineering	MEUR	1.5
Purchase Ground	MEUR	5
Compressor Units	€/kW	2,113
EPC contract	MEUR	$3\ MEUR + 0.62\ \frac{MEUR}{MW} \times C_{Compression}$
Electrical supply	MEUR	10

The capacity of the compressor units is calculated according to (André et al, 2014):

$$C_{Compression}[kW] = Q \times \frac{Z \times T \times R}{M_{H2} \times \eta_{comp}} \times \frac{N \times \gamma}{\gamma - 1} \times \left(\left(\frac{P_{out}}{P_{in}} \right)^{\frac{\gamma-1}{N \times \gamma}} - 1 \right)$$

Here, Q is the max. hydrogen production rate [kg/s]; Z is the dimensionless compressibility factor of 1.01; T is the inlet temperature of the compressor assumed to be 293 K; R is the universal constant of ideal gas of 8.31 [J/(mol * K)]; $M_{hydrogen}$ is the molecular mass of hydrogen assumed to be 2.02 [g/mol]; η_{comp} is the compressor efficiency ratio of 75%; γ is the diatomic constant factor of 1.4; P_{out} is the outlet pressure of the compressor of 50 bar; P_{in} is the inlet pressure of the compressor depending of 17 bar in case of offshore P2G (Scenario 2 and 4) or 30 bar in case of onshore P2G (Scenario 1 and 3).

4.3.5 Pipeline infrastructure

Routing

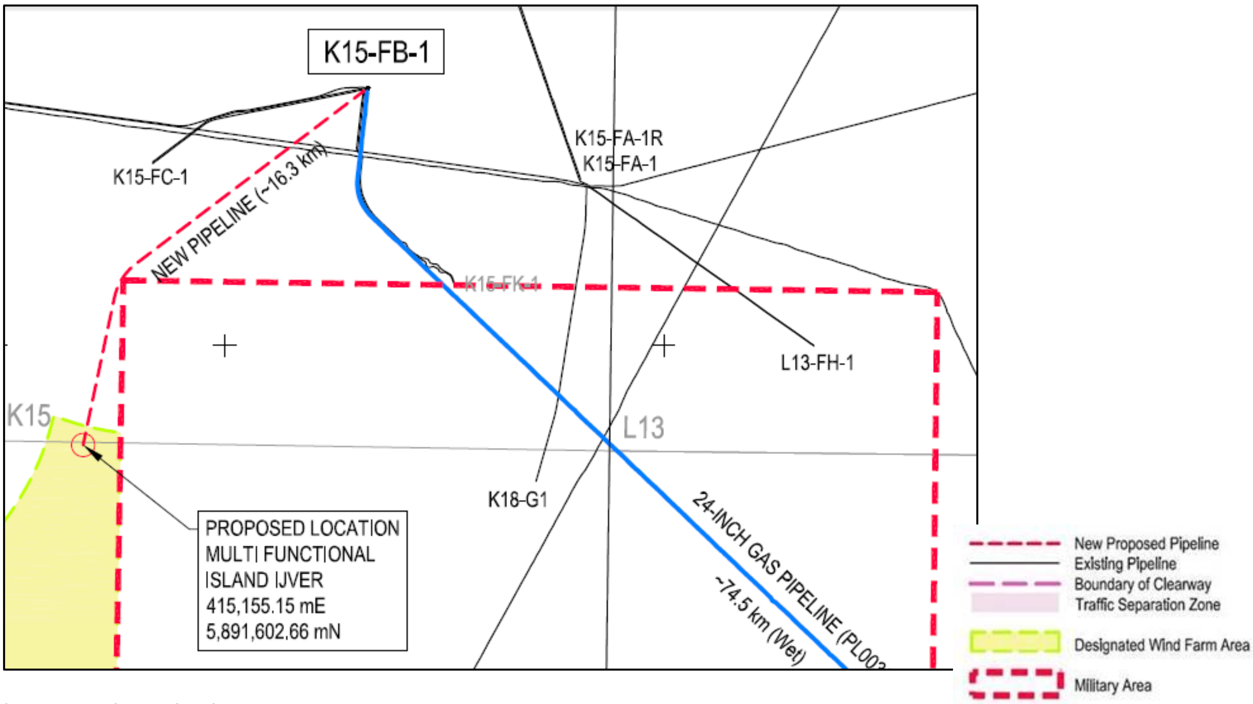
There are three major pipelines (NGT, WGT and LOCAL) located relatively close to the island location that have individually enough capacity to transport the hydrogen produced at peak wind capacity (see also Section 3.2.2). The 24-inch LOCAL pipeline, running from K15-FB-1 to Den Helder,was selected for this study as being the geographically most interesting candidate for three reasons (See also Figure 30 & Appendix F.2)[24],[25]:

1. The pipeline runs reasonably close to the projected IJver island location.
2. The K15-FB-1 platform is also close to the IJver island location which provides easy access to the export pipeline and allowing pigging facilities on the platform for both the new pipeline (receiving) and existing pipeline (launching) segments which will allow internal inspection.
3. Den Helder was considered a suitable landing location.
4. The pipeline capacity suffices to transport all hydrogen produces at peak wind capacity (see section 4.3.4).

[24] Pipeline system owners may already be developing plans for pipeline life extension which may include reuse for CCS. These development plans have not been considered in the selection criteria, though, might affect choice of routing.

[25] The K15-FB-1 platform will - based on the 'most likely' scenario (Nexstep, 2018)- in use for natural gas transmission beyond 2027. It is assumed that upstream and downstream platforms attached to the LOCAL pipeline can be diverted to the WGT-pipeline systems. Further research on the cost and technical possibilities of connecting these upstream and downstream platforms to the WGT is required (see also section 4.3.5).

Figure 30 - Pipeline export systems Dutch Continental shelf considered in this study



Source: (Rijksoverheid, ongoing).

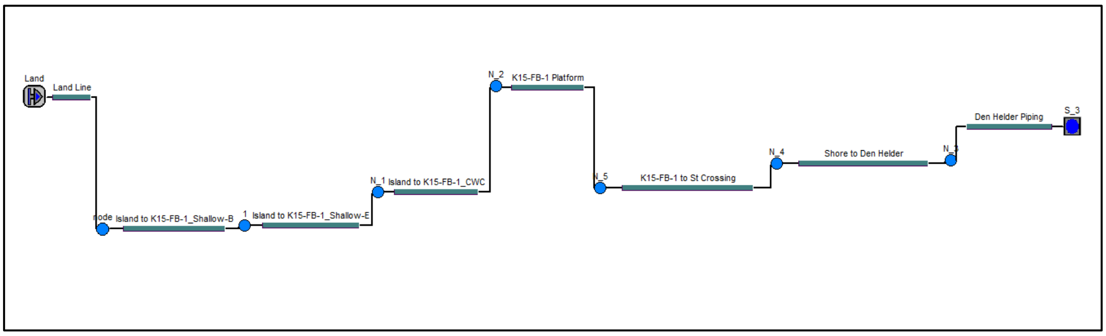
Flow assurance

In combination with the 24 inch existing export pipeline from K15-FB-1 to Den Helder, the internal diameter for the new pipeline section connecting the energy island to K15-FB-1 was determined by creating a flow assurance model.

The hydrogen export system is modelled using the hydraulic analysis program PIPESIM version 2012.2 with the Moody single phase flow correlation; the schematic PIPESIM model is shown in Figure 31.

The fluid properties (100% gas hydrogen) are characterized using Multiflash Version 4.3 (built-in version in PIPESIM).

Figure 31 - Schematic of PIPESIM Model from Windpark Island to Den Helder via K15-FB-1 Platform



With the anticipated export pressure of the electrolyser while avoiding the need of additional compression at the IJver Island, an inlet pressure of 30-35 bar was selected.

By implementing the existing pipeline configuration and mechanical properties with the target flowrates, the hydraulic analysis was carried out to determine the minimum required pipeline size for the new pipeline section for the demanded flow capacity.
The hydrogen export system consists of a possible new pipeline and an existing 24-inch pipeline. Therefore, the flow capacity assessment was carried out by varying the new pipeline size in combination with the existing 24-inch pipeline. It must be mentioned that the current hydraulic study is aimed at free flow capacity assessment. No offshore compression facility is considered, though might be required if the scale of hydrogen production increases in the future.

Figure 32 displays the different new pipeline size and the associated pressure drop across the entire pipeline system by fixing the flowline inlet pressure of 35 bar. It shows that the minimum required new pipeline size of 12.75-inch and 14-inch is needed for the Average flow and Peak flow cases with the associated pressure of 22.7 bar and 31.5 bar, respectively. Below the minimum required new pipeline size, the hydrogen flow is unable to be delivered, due to the higher pressure drop than the system limitation. This is because the flow approaches the hydraulic limitation.
Moreover, the results also indicate that the flow becomes unstable for the peak flow scenario if the 14-inch OD is used due to the significant pressure drop and gas velocity increases. Therefore, it is suggested to take account a safety margin for the stable flow transportation and selected a 16 inch diameter for the new pipeline section (See Figure 32). Although the presented result presents a 35 bar electrolyser pressure this conclusion is also valid for a 30 bar pressure.

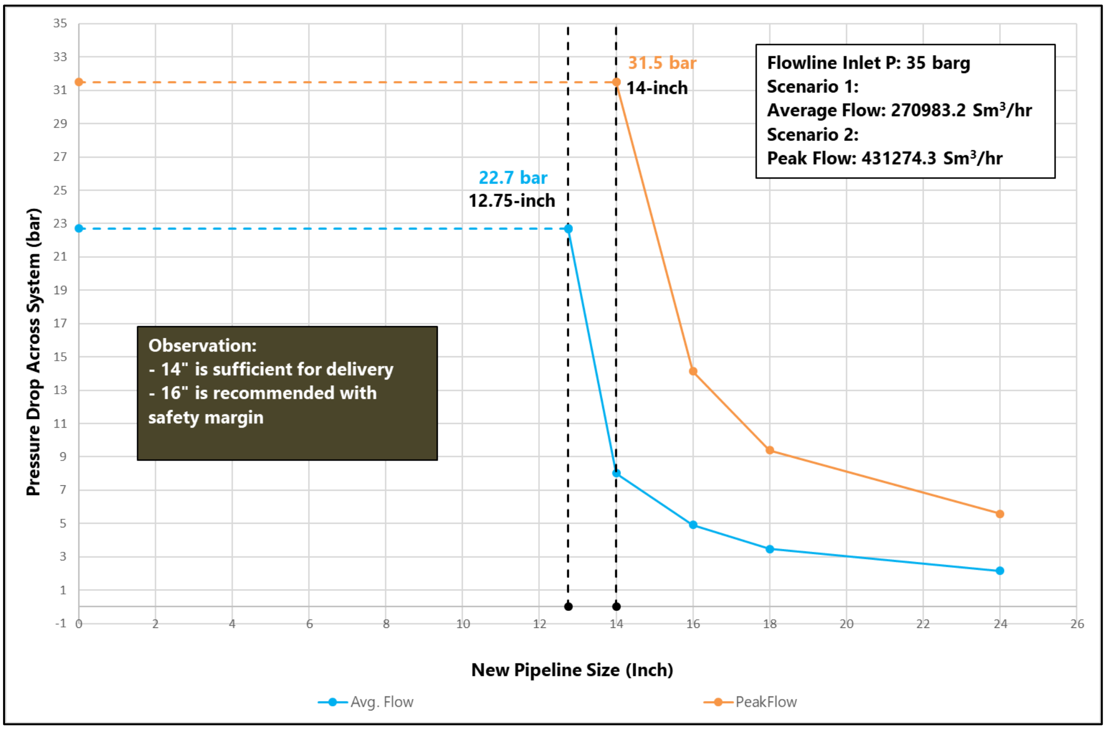
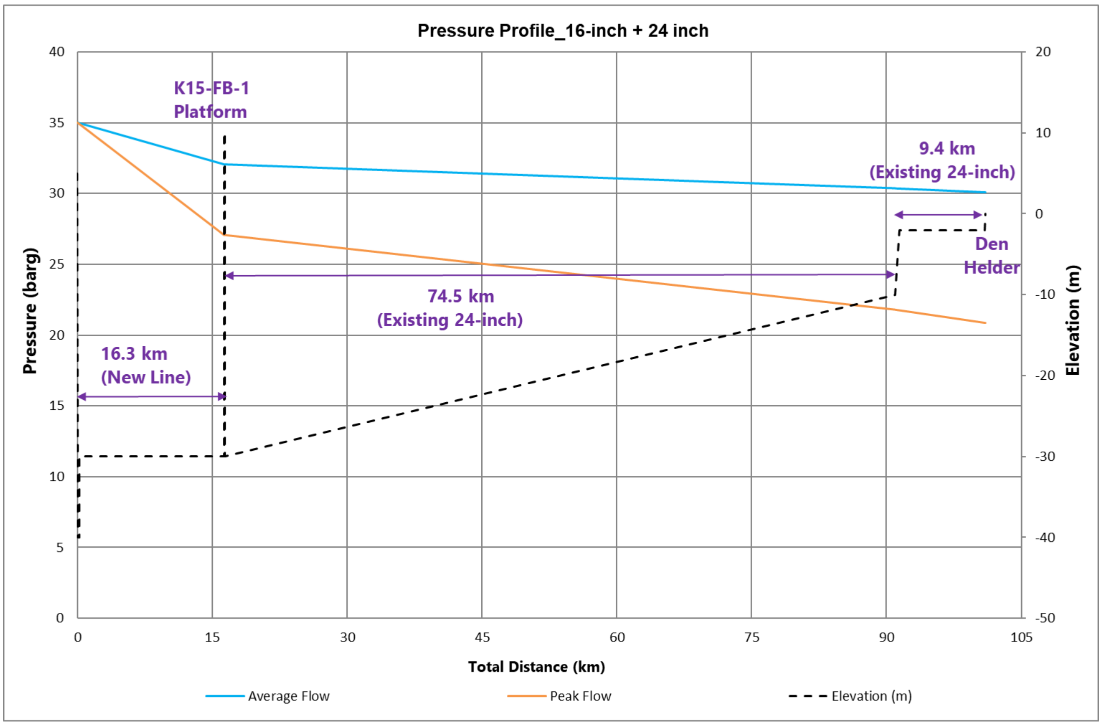


Figure 32 - New Pipeline Sizing with Pressure Drop across Entire Pipeline System

The resulting overall pressure profile is included in Figure 33.

Figure 33 - Pressure Profile across Entire Pipeline System – 16-inch New Pipeline Size



Pipeline design new 16-inch line

The project code NEN 3656 "2015" refers to NEN 3650 "Eisen voor buisleidingsystemen" which refers to ISO 3183 for offshore pipe line systems; ISO 3183:2019 refers to the API 5L 46th edition to be followed for offshore line pipe. Further NEN 3656 and NEN 3650 do not provide specific requirements for the transportation of hydrogen, as such the latest version of ASME B31.12 "2019" is followed. The ASME B31.12 provides additional information for hydrogen projects in combination with API 5L line pipe.

Material delection: Pipeline steel

Although details on the effects of the steel composition and microstructure on hydrogen embrittlement is not fully understood yet, a lot of engineering data is available for some materials. In general, the susceptibility to hydrogen embrittlement increases as the material strength and hardness of the steel increases. There are hundreds of kilometers of hydrogen gas transportation lines installed and the experience shows that low grade steels up to API 5L PSL2 X52 are recommended. This in combination with a tendency to limit the gas pressure and pipeline dimensions in such a way that the wall stresses are less than 30% to 50% of the specified minimum yield strength.
Because of the low pressure and due to the limited effect (strength reduction factor) of using a higher grade steel it is advised to stay with the lower grade steel of X52 PSL2 offshore grade steel which is similar to SAWL 320 M.

Wall thickness

For L360/X52 material and design pressures up to 50 bar and design temperatures up to 50°C, the required wall thickness is determined by (propagation) buckling criteria and not burst (even for the high safety zone near populated areas). The required wall thickness to fulfil the NEN 3656/ASME B31.12 requirements is 8.4 mm including fabrication tolerances (corrosion allowance 0 mm). This is well below the minimum wall thickness generally adopted (for example DNVGL offshore standard; min 12.5 mm) for offshore pipeline installation by lay barge. It is therefore recommended to consider at this stage the standard wall thickness of 12.7 mm, which also provides a margin for additional tolerances (for other fabrication methods than SAWL) and allowances (> 0 mm corrosion allowance).

Coating

For the multifunctional island connection a three layer polypropylene (3LPP) with a rough outer layer is foreseen which is a robust coating system for offshore installation. A standard 3 to 4 mm 3LPP would suffice.

Pipeline stability assessment

It is assumed that even when burial is relied on for the long-term stability that the required specific weight of the new pipeline has to be more than 1.3. Considering the wall thickness of 12.7 mm for the new line and assuming nowadays standard concrete density of 3,340 kg/m^3, a weight coating thickness of 50 to 70 mm gives a specific weight of 1.7 to 1.9.

Considerations related to reuse of existing pipelines

The existing line of 24-inch has a wall thickness of about 12 mm and a material grade equivalent to X60 (STE 415.7). For this material a strength reduction factor of 0.874 applies (effectively reducing it to X52). If the full wall thickness is still available, this thickness is sufficient for (propagating) buckling and an internal design pressure of up to 100 bar (=original design pressure) and a design temperature of 50°C. Given the fact that the pipeline is already installed, a risk assessment has to determine the acceptability of some wall thickness reduction due to corrosion from a buckling point of view. Given the low required pressure for hydrogen transport, the design pressure can be reduced to 50 bar to match the remaining wall thickness from a burst point of view. For 50 bar and the full wall thickness the yield utility factor is 0.36, remaining below the 40% of SMYS mentioned in ASME B31.12 to limit the risk of running fractures during operation.
In addition a fitness for purpose study needs to be completed. Section PL-3.21 “Steel Pipeline Service Conversions” of ASME B31.12 can be used for a fitness for purpose study when an existing pipeline is used. An 18 point list is given that needs to be followed to understand whether a conversion is possible and can be qualified. The shortened list can be found below (numbering of ASME B31.12 is maintained):

a Risk assessment in line with PL-3.5 (size of potential impact radius and amount of buildings intended for human occupation are in this area). This risk assessment should be replaced by an offshore risk assessment option.
b Study all available information on the original pipeline, pending the amount of data that is still available more research may be required for the offshore section.
c Study operational and maintenance data, this is to understand the current condition of the pipe based on a desktop study.

d If the original mill certificates are not present, the material description shall be determined by chemical and physical analysis of samples taken every 1.6 km of pipe. This will be a challenge.
e The material shall be qualified for fracture control. However, if the MAOP results in a hoop stress > 40% SMYS, then this requirement is cancelled.
f Evaluation to be executed for any wall thickness reduction factors, including imperfect CP or internal corrosion, and damage due to surface activities. This will can be seen as part of item e) above.
g Weld and base metal coupons to be taken every 1.6 km to check for weld inclusions, and for material properties as hardness, yield strength, and tensile strength.
h Determine that all valves, flanges, and other pressure rate components have adequate ratings.

The main challenge will be item n) above as this implies cutting into a pipeline which can only be done onshore and will require repair afterwards. If test data from the original pipe including inspection data from installation is available this may solve the challenge.

Installation method statement

The crossing of the IJver seadefense is a critical part of the route. There are two installation methods that can be considered:
1. Including the shore crossing works as part of the overall island construction works by means of a caisson or alternative structural aid that is installed as part of the IJver seadefense construction works. The objective would be that the pipeline can be installed by pulling back through this caisson.
2. Install the IJver pipeline shore crossing after completion of the island by means of Horizontal directional drilling (HDD) or alternative trenchless method.

For the purpose of this estimate it is not expected that there will be a considerable cost difference between the two methods and the cost for a shore crossing by means of HDD are reflected in the estimate.
The pipeline will be pulled back through the HDD and the pipelay vessel will continue laying, or alternatively a sufficient long tail will be left on the seabed for recovery by the pipeline installation vessel at a later date.

The lay-vessel will lay towards the K15-FB-1 platform. The pipeline will be installed on the seabed and possibly post-lay trenched. However, for a 16 inch pipeline this is not required. For this cost estimate, a single joint DP pipelay vessel is assumed. On the route 2 crossings at close vicinity are required over the WGT pipeline and the K15-FA-1 to K14-FA-1 pipeline. At K15-FB-1 a tie-in spool and riser will need to be installed.
The benefit of having the K15-FB-1 platform at the receiving end of the new pipeline section will be important for the initial pre-commissioning and drying works of the new pipeline section, but also for operational inspection of both the new and existing elements of the IJver hydrogen export system.

Cost estimate

The above conceptual pipeline design and installation method statement formed the basis for the export system cost estimate.
The resulting overall Total CAPEX is about 60 million Euro (P50) with a calculated accuracy of -26%/+38%. This is in line with the accuracies that can be expected at this stage of the project development with minimal survey data available and limited engineering work completed. Table 10 - Table 11 provides the overall result of the estimate.

Table 11 - Results of estimate

				Total	Acc. Cost		Cost low/high	
							Cost Low	Cost High
				Euro	-	+	Euro	Euro
Total Direct Cost				***41,271,190***	***27%***	***40%***	***29,923,361***	***57,685,193***
Detailed design & EIA	mhrs	25,000	90	900,000	15%	20%	765,000	1,080,000
Company PMT	%	5%		2,063,560	15%	20%	1,754,026	2,476,271
Insurance & certification	%	3%		1,238,136	15%	30%	1,052,415	1,609,576
Total Indirect Cost				***4,201,695***	***15%***	***23%***	***3,571,441***	***5,165,848***
Total Direct and Indirect Cost				***45,472,885***			***33,494,802***	***62,851,041***
Contingency	%	20%		***13,641,866***			10,048,441	18,855,312
Overall Total CAPEX Pipeline				***59,114,751***	***26%***	***38%***	***43,543,243***	***81,706,353***

The above values for the new pipeline sections including facilities at both ends are combined with an allowance for the preparation for hydrogen transport of the existing facilities (existing K15-FB-1 to Den Helder pipeline and modification works at Den Helder plant). Note that these figures are very generic and could not be confirmed as part of the current study. Table 12 presents the Total CAPEX for the Hydrogen export system to be used for economic modelling.

Table 12 - Total CAPEX Hydrogen export system

Capex		P10	P50	P90
1	Preparation K15-FB-1 to Den Helder pipeline (make gas free + fit for purpose survey)	1,000,000	2,000,000	3,000,000
2	Prepare den Helder plant for receipt hydrogen (EPC)	5,000,000	7,000,000	10,000,000
3	new 16 inch pipeline + Connection at K15-FB-1	45,000,000	60,000,000	80,000,000
		51,000,000	**69,000,000**	**93,000,000**

Table 13 provides an overview of the annual survey cost and an allowance for corrective maintenance as input for economic modelling. Where inspections are not required on an annual basis, the costs are averaged over the years. It is also assumed that the inspections can be combined with other inspection works (reduced mob/demob costs).

Table 13 - Total OPEX (inspections and maintenance) Hydrogen pipeline export system

Opex per year		P10	P50	P90
1	Annual hydrographic survey 16"+24" (excl mob/demob)	50,000	70,000	90,000
2	Internal inspection 16" + 24" (year 1,3,5,10)	150,000	250,000	300,000
3	Landfall and onshore survey K15-FB-1	12,000	25,000	35,000
4	Corrective maintenance	50,000	80,000	120,000
		262,000	**425,000**	**545,000**

The P50 values of pipeline CAPEX & OPEX are selected for the subsequent scenario calculations.

4.4 General economic and capacity assumption

4.4.1 Economic assumptions

Price adjustment to 2020 values

The values shown in the report are today's real values. Where original data is based on different years, we take into account the price change based on the harmonised consumer price index (HCPI) provided by the European Central Bank (ECB , Ongoing).

Weighted average costs of capital

For the analysis of the business case we make use of the discounted cash flow method. One essential part of it is the weighted average cost of capital (WACC) that specifies minimum return on investments. The investments that are considered in this study are assumed to be financed from both equity and debt. Depending on the risk and market conditions, the respective capital providers have different return expectations. As the results and values mentioned in this report are before taxes, we do not take into account a tax-shield i.e. taxation and potential deductions on taxable income. The WACC before taxes is then calculated according to the equation below.

$$WACC = \frac{E}{V} \times R_e + \frac{D}{V} \times R_d$$

Here, V is the total value of capital, E/V is the percentage of capital that is equity, D/V is the percentage of capital that is debt, R_e is the cost of equity, and R_d is the costs of debt. In our calculations we base the WACC on a 70% debt share, an expected rate of return of 10% for equity and a debt interest rate of 6%. This results in a **WACC of 7.2%**.

General and administration and insurance expenditures

General and administration (G&A) expenditures relate to the daily operations of the business and include: Salaries for technical and commercial management, accounting, legal counsel; Marketing & sales; Utilities and office supplies; Consultant fees; Insurance, etc.

In our study we derive the G&A expenditures by applying a fixed "overhead" percentage to average direct expenditures of the business operations:

Equation 3: Calculation of G&A expenditures

$$OPEX_{G\&A} = Relative\ G\&A\ percentage \times \frac{\sum_{i=0}^{n} OPEX_{direct} + \sum_{i=0}^{n} depreciation_{direct}}{n}$$

where n = project lifetime [a] and the relative G&A percentage is 20%

The G&A expenditures are taken into account from the beginning of investment until the end of operation and form together with the direct OPEX the total annual OPEX of the business operations.

Average annual downtime

Another important factor for the profitability of the business operations is the total availability of the system. In our analysis we take a ballpark **annual 5% of system downtime** into consideration.

When calculating the model's output flows *hydrogen to market* and *electricity to market* the flows are reduced by 5%.

Discounted Cash-Flow and NPV

We use the capital value method in order to have an indicator for scenario comparison reasons but also to evaluate the business case of each scenario individually. In short, the capital value method takes into account that early earnings are worth more than late ones. Deposits and withdrawals that are summarised in the annual cash-flow are discounted with the WACC. The cumulated discounted cash-flow results in the net present value (NPV) of the scenario specific investment at the current time. The NPV is calculated according to:

$$NPV = -I_0 + \sum_{t=1}^{n} \frac{Cash\ flow_t}{(1+WACC)^t}$$

Here, I_0 is the initial investment in 2026, Cash $flow_t$ equals the annual cash flow for period t, n=24 the project duration minus the initial year.

Levelised costs

We use the levelised cost method for calculating the average production costs of hydrogen (LCOH) and electricity (LCOE). Since there are in some scenarios hybrid systems where costs cannot exclusively allocated to either the P2G plant or the electric power conversion system only, the costs of shared components are allocated based on the generated power by the wind farm determined for the P2G plant versus feeding-in the onshore transmission grid (Table 14).

Table 14 - Levelised cost equations per scenario

Scenario	Levelised cost equations
Scenario 1 and 2	$$LCOH = \frac{\sum_{t=0}^{n} \frac{CAPEX_{total,t} + OPEX_{total,t}}{(1+WACC)^t}}{\sum_{t=0}^{n} \frac{Annual\ hydrogen\ production_t}{(1+WACC)^t}}$$ LCOE is not applicable
Scenario 3[26]	$$LCOH = \frac{\sum_{t=0}^{n} \frac{\frac{E_{1,t}}{E_{1,t}+E_{3,t}} \times \left(CAPEX_{ELT,t} + OPEX_{ELT,t}\right) + CAPEX_{P2G,t} + OPEX_{P2G,t}}{(1+WACC)^t}}{\sum_{t=0}^{n} \frac{Annual\ hydrogen\ production_t}{(1+WACC)^t}}$$ $$LCOE = \frac{\sum_{t=0}^{n} \frac{\frac{E_{3,t}}{E_{1,t}+E_{3,t}} \times \left(CAPEX_{ELT,t} + OPEX_{ELT,t}\right) + E_{3,t} \times LCOE_{WP}}{(1+WACC)^t}}{\sum_{t=0}^{n} \frac{E_{3,t} \times \eta_{EL}}{(1+WACC)^t}}$$

26 $CAPEX_{P2G}$ and $OPEX_{P2G}$ includes the electrolysis, pipeline, compressor and water treatment system. $CAPEX_{ELT}$ and $OPEX_{ELT}$ includes the converter, the cable, the onshore and the platform. The expenditures for an offshore platform are only considered in Scenario 1 & 3 where there is no island but an offshore substation. $CAPEX_{island}$ and $OPEX_{island}$ are only considered in Scenario 2 & 4 where the offshore substation is located on the island.

Scenario	Levelised cost equations
Scenario 4	$LCOH = \frac{\sum_{t=0}^{n} \frac{\frac{E_{1,t}}{E_{1,t}+E_{3,t}} \times (CAPEX_{ELT,t} + OPEX_{ELT,t}) + c_{P2G} \times (CAPEX_{island,t} + OPEX_{island,t}) + CAPEX_{P2G,t} +}{(1+WACC)^t}}{\sum_{t=0}^{n} \frac{Annual\ hydrogen\ production_t}{(1+WACC)^t}}$ $LCOE = \frac{\sum_{t=0}^{n} \frac{\frac{E_{3,t}}{E_{1,t}+E_{3,t}} \times (CAPEX_{ELT,t} + OPEX_{ELT,t}) + c_{ELT} \times (CAPEX_{island,t} + OPEX_{island,t}) + E_{3,t} \times LCOE_{WI}}{(1+WACC)^t}}{\sum_{t=0}^{n} \frac{E_{3,t} \times \eta_{EL}}{(1+WACC)^t}}$

Here, $CAPEX_{P2G,t}$ and $OPEX_{P2G,t}$ are the expenditures directly linked to the P2G plant; $CAPEX_{ELT,t}$ and $OPEX_{ELT,t}$ are the expenditures that are linked to electric power conversion; $E_{1,t}$ is the electricity generated by the wind park that is directed to the P2G plant; $E_{3,t}$ is the electricity generated by the wind park that is fed-in the onshore transmission system; c_{P2G} is the island cost allocation factor for the P2G plant; c_{ELT} is the island cost allocation factor for the offshore substation [27].

4.4.2 Capacity assumptions

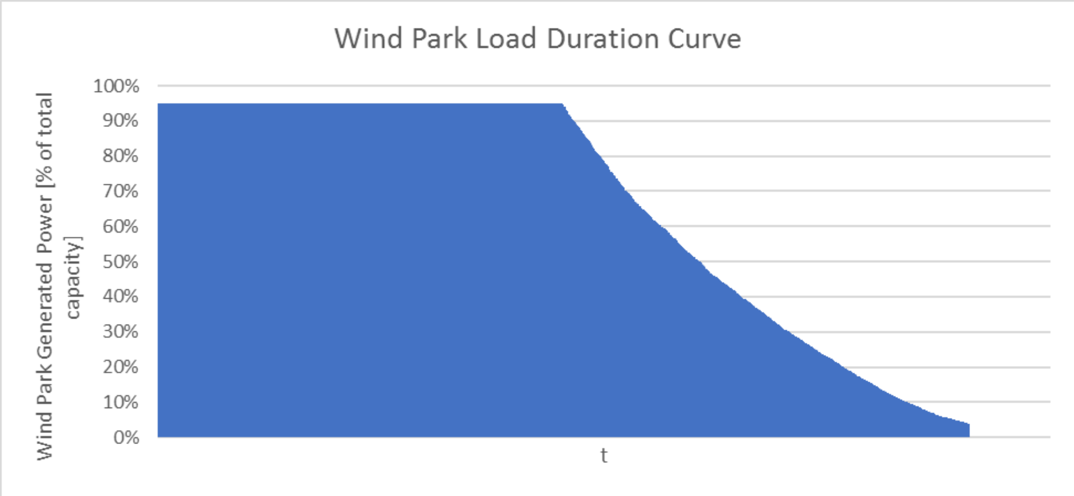
Wind park electricity generation

The electricity generation profile of wind park is based on available data of the Dutch meteorological institute KNMI (Koninklijk Nederlands Meteorologisch Instituut, 2020) for location specific estimates of 2017 wind speeds in combination with specs (power curve) of the Haliade X wind turbine. The outcome is a load factor of 61% that seems to be solid when compared to the world's largest offshore turbine specs of the GE Haliade-X 12 MW with a mentioned load factor of 63%[28]. The profile has a maximum load capacity of 95% due to included cable losses and dimensioning of the wind blades to achieve a longer period of constant load despite it reaches a lower technical maximum. The results of the simulation are shown in form of a wind duration curve in .

27 For a breakdown of the island cost allocation factors we refer to section '**Fout! Verwijzingsbron niet gevonden.**'(p. 20).

28 GE Renewable Energy : Haliade-X 12 MW offshore wind turbine platform

Figure 34 - Normalised wind duration curve of the simulated data of a future offshore wind park



Electrolyser capacity optimization outcomes

A separate model has been developed to calculate the optimal electrolyser capacity based on the cost-price of hydrogen and given a specific wind duration profile. The results of the simulation enter the model as exogenous variables (capacity factor wind power generation & electrolyser capacity). The analysis was carried out on the basis of a simulation of a wind park in the IJmuiden Ver area for the period of 2025-2030 and led to a total load factor of about 61 % mostly due to higher wind speeds offshore and future large turbines. [29][30]

As it is the case for many P2G related projects, eventually, the model needs to determine the electrolyser capacity at which the cost of hydrogen is the lowest. The levelised costs consist of the three main elements levelised CAPEX, O&M costs and electricity costs. The capital investment with the most impact on the business case is the one for the electrolyser unit and its auxiliary equipment. The particular situation of our case where an electrolyser plant is coupled to a wind park comes usually with one complication: common wind parks operate with a relatively low load factor whereas one would prefer to utilise the capital intensive electrolyser unit to its maximum. In this theoretical concept one can optimise taking the levelised costs of hydrogen production (LCOH) as an optimisation criteria.

$$LCOH\left[\frac{€}{kg}\right] = CAPEX\,[€/kg] + \;OPEX\,[€/kg] + Electricity\;consumption\,[€/kg]$$

Here, m equals the start year of the hydrogen production period; n equals the end year of operation. Appendix C.1 explains the composition of the input parameters and the associated equations related to the optimisation analysis.

By reducing the P2G plant capacity one can observe the following:

- As a direct relation, the total investment costs of the P2G plant and the CAPEX dependent OPEX decrease and so does the numerator of the LCOH equation.

29 Data has been retrieved from ECN as input for (Jepma & van Schot, 2017).

30 700 MW has been chosen as a standard tender size for the to be installed wind parks in near future until 2026 (Borssele, Hollandse Kust Zuid, Noord, West, Ten Noorden van Waddeneilanden). Actual approved wind park capacities differ depending on wind park design. See also RVO : Development of Offshore Wind Farms in the Netherlands

- Less electricity of the wind farm can be converted to hydrogen because of capacity constraints. Since the produced hydrogen is in the denominator the LCOH increases.
- Both previously mentioned effects differ in terms of their impact on the LCOH. As a consequence, one can determine the optimum capacity by comparing the LCOH of different electrolyser capacities and selecting the capacity with the lowest LCOH.
- The full load hours of the electrolyser increase since the effect of peak wind power generation is reduced. The generation profile becomes more baseload the more the P2G plant capacity is reduced. Though, this effect has no direct impact on the LCOH.

On the one hand, we can observe a cost-lowering impact of curtailment with regard to the decreasing electrolysis CAPEX. However, on the other hand the specific electricity costs increase since the electrolyser operator does also have to pay for the electricity which has not been made use of. In total, the relative decrease of the CAPEX does not outweigh the increasing specific electricity costs. The optimal electrolyser capacity equals the maximum of the optimized wind park load curve (about 95%) without extra curtailment. According to that, the full load hours of the electrolyser are some 5,500 hours (capacity factor of ~64%)

4.4.3 General capital cost assumptions

Offshore cost factor

Increasing material requirements in offshore domains and larger costs related to bring workforce to an offshore location for construction and maintenance purposes will likely lead to higher costs compared to the conventional onshore case. In our calculations we use a ballpark cost factor to contemplate the harsher offshore environment. This cost factor is applied to CAPEX ($c_{Capex}=1.5$) and OPEX ($c_{opex}=1.5$) of the offshore installation of which the original cost estimates are based on common main land applications.

Economies of scale

Economies of scale is a concept which basically describes to what extent the specific costs of a full plant or just a production process decrease with increasing production volumes. In our study the term economies of scale solely refers to the effect of **real cost reductions** when production volumes are increased but **excludes any other form of upscaling** (e.g. larger electrolyser modules with higher rated power). Economists widely agree that increased scale in production capacity reduces the capacity specific cost of the producing equipment, related labour and other internal economies disproportionally (Haldi & Whitcomb, 1967) (Silberston, 1972) (Teitel, 1974) (Tribe & Alpine, 1986). The general equation of the relation between production capacity and costs can be expressed as shown in Equation 4:

Equation 4 - General equation for economies of scale

$$C_b = C_a \times (\frac{S_b}{S_a})^f$$

Where $0 \leq f \leq 1$

C_b = actual plant/product costs; S_b = actual scale of the plant/product; C_a = costs of the known reference plant/product; S_a = scale of the known reference plant/product; f = scale factor

The constraints of this broad concept are diverse but referred to in depth in the mentioned literature. In our system we assume that the equation is valid under the condition that the main considerations like technology and price structure are fixed, and labour and raw materials are sufficiently available. In general engineering designs the scale factor is commonly chosen to be 0.6, also referred to as the “0.6 rule” or “0.6 method” (Tribe & Alpine, 1986). The studies mentioned also provide some information about specific scale factors for certain products (Silberston, 1972), (Teitel, 1974) and certain industries (Haldi & Whitcomb, 1967) , however, the empirical value of the scale factor varies mostly between 0.3-0.9 (Teitel, 1974), (Tribe & Alpine, 1986). Thus, if the 0.6 method is applied, the result should be considered rather sensitive. To stay on a more conservative side we a scale factor of 0.8 to the electrolyser, water treatment and compression system.

Decommissioning and rest value

With regard to the inclusion of decommissioning costs, there is no project specific data available yet. In general, we assume that the terminal value of the equipment is sufficient to balance the decommissioning costs.

5 Techno-economic scenario results

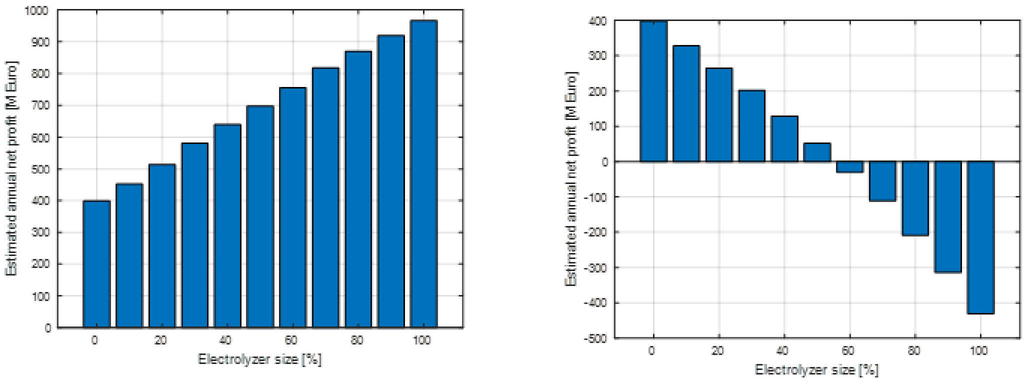
In this chapter the main results of the techno-economic assessment of the economics of developing an multifunctional energy island are presented. These results are based on the four main scenarios outlined in Chapter 3. The modelling approach and details are presented in Chapter 4.

5.1 General results: Share of conversion

These general results are based on Scenario 4 — island hybrid — optimal cable. The main question is to determine which part of the energy in the optimal case should be converted into hydrogen offshore (x%), and which part is transported to shore via a DC power connection (1-x%). In order to determine the optimum x, another model has been developed. This model maximises the total energy system net revenues. The model calculates costs and revenues from all possible combinations of x, i.e. ranging from 0% (indicating no electrolyser is installed and all wind power will be transmitted via HVDC) to 100% (indicating no HVDC is installed and all wind energy will be converted into hydrogen), based on CAPEX & OPEX (Section 4.3), hydrogen and electricity day ahead market prices (year 2029, Appendix E), and a developed energy management strategy (Appendix F.3). The CAPEX costs are provided as functions of the equipment rating. The OPEX costs are estimated as a percentage of the CAPEX. Finally, the total cost is normalised over the lifetime of the equipment to obtain a cost in [€/hour] for hydrogen production and electricity transmission.

The results for the low hydrogen price scenario (, right side) show an inverse relation between total net system revenues and the relative size of the electrolyser system (x). In other words, it is optimal not to convert any part of the power produced into hydrogen: in the optimum x=0%. For the high hydrogen price case the conclusion is completely the opposite one: net returns are maximized if all power is converted into hydrogen offshore (x=100%). Obviously, the cases in which x has a certain value in the optimum will materialise for hydrogen per kg prices between 1.5 €/kg and 6.0 €/kg.

Figure 35 - The impact of electrolyser size on total system revenues in the 6.0 €/kg scenario (left side) and in the 1.5 €/kg scenario (right side)



The explanation is as follows. If the hydrogen price is low, a hypothetical electrolyser operator will use power from the wind farm and from the onshore grid, but only up to the point at which power prices will allow him/her to break-even with hydrogen returns. For this case, the cut-in electricity price for hydrogen production is calculated to be just below 30 €/MWh. This means that in the day ahead price scenario, the electrolyser has a load factor of only 19% and can therefore not run cost-effectively. Theoretically the electrolyser business case could improve if flexibility services could be provided in addition to hydrogen, but the model used does not take this account.

By contrast, the high hydrogen price scenario results projected at the left side of , show that the net system revenues are maximized if all power is converted into hydrogen. In this case the cut-in electricity price for hydrogen production is almost 115 €/MWh, which results in a load factor of 97% and therefore a sound business case for offshore hydrogen generation.

The optimisation of infrastructure for a multifunctional island depends significantly on the assumed value of hydrogen. Given the wide spread of hydrogen market values, the optimisation process yields no optimisation between electricity and hydrogen equipment size but favours completely only one over the other: electricity when prices are low, and hydrogen when prices are high.

As a result, further analysis is required to determine whether a hybrid system would be beneficial when differing hydrogen and electricity prices are taken into account. Therefore, the following sub-sections present an analysis of this scenario to examine at which hydrogen price (between 1.5 and 6 €/kg) the shift occurs from favouring an all HVDC solution to an all hydrogen solution. The general results presented in sections 5.2 - 5.5 are, however, presented for the two hydrogen prices mentioned only. Thus, scenario Island hybrid - Optimal cable is not further presented in detail in those sections, as it would equal scenario Island hybrid - Maximal cable under these circumstances.

5.1.1 Specific optimisation outcomes – day ahead prices

Given the electricity price profile of 2029 (the same profile that was used in earlier analysis), a search routine is implemented in MATLAB in order to find the price of hydrogen at which full electricity system returns the same profit as an all hydrogen system. This threshold price is found to be about 4.36 €/kg. Figure 36 hows the profits for different sizes of the system.

Figure 36 - Estimated annual net profit with a hydrogen price of 4.36 €/kg

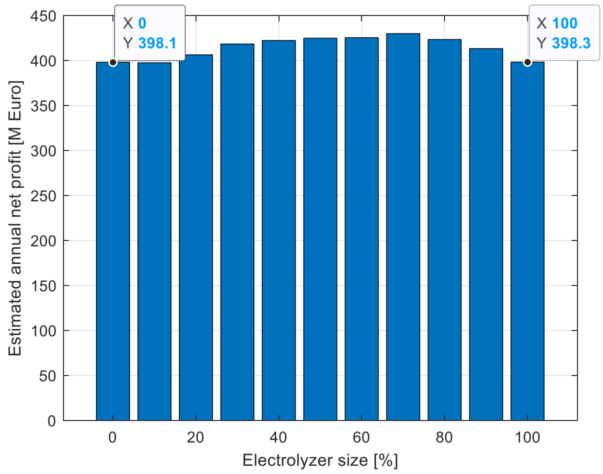
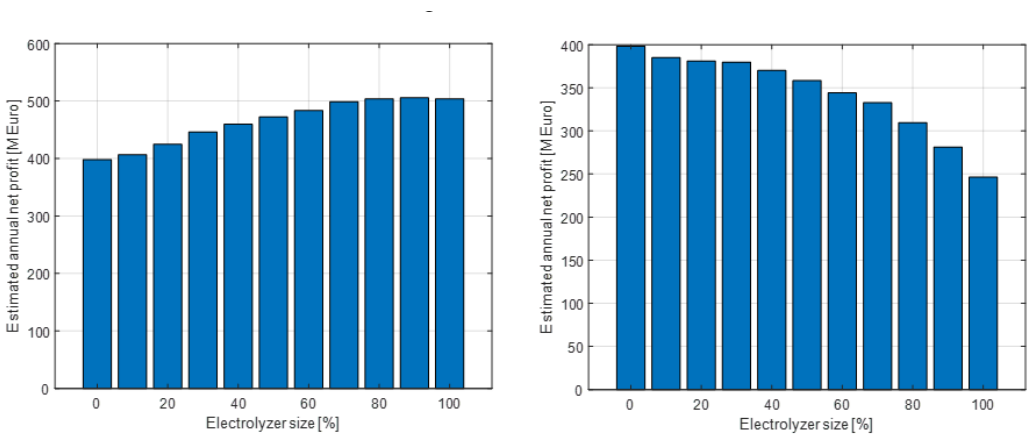


Figure 36 shows the profits from an all electricity solution (x=0%) and an all hydrogen solution (x=100%) are almost equal. It's also interesting to note the presence of a maximum at x=70%.

If the hydrogen price goes above this 4.36 €/kg threshold, the maximum occurs at x=100%. Conversely, if the hydrogen price goes below this threshold, the maximum occurs at x=0%. This is demonstrated in Figure 37:

Figure 37 - Annual net profit given a hydrogen price of 4.6 €/kg (left) vs. 4 €/kg (right)



5.1.2 Specific optimisation outcomes - bilateral contract

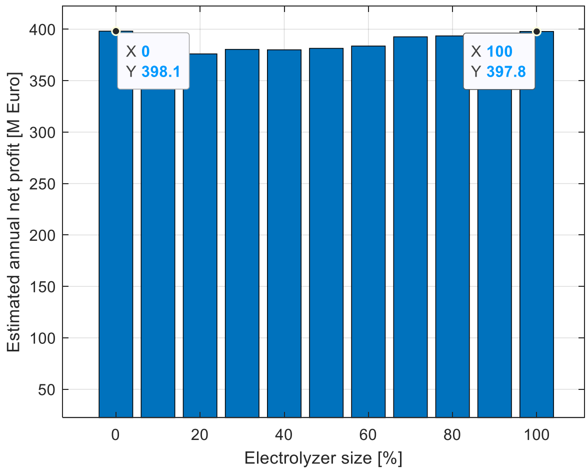
In this case, an assumption of a fixed bilateral price between P2G and wind park operators of 40 €/MWh is made. This assumption has an immediate effect on the energy management strategy. The choice of using wind power to generate hydrogen is made at each hour based on the electricity cut-in price (see also Section 4.2.4):

$$p_{e,cut-in}[\frac{EUR}{MWh}] = \frac{p_{hydrogen}[\frac{EUR}{kg}] * 1000}{\eta_{electrolysis}\left[\frac{kWh}{kg}\right]}$$

In the previous case, where a variable day ahead electricity price is assumed, the energy management algorithm needs to check every hour if the price of electricity is favourable for hydrogen production. However, in this case, since the electricity price is assumed flat, we can determine beforehand whether the chosen the minimum hydrogen price for which production is favourable, given electricity cost of 40 €/MWh. This was found from the equation above to be 2.1 €/kg.

Therefore, in this case, the breakeven price is between 2.1 and 6 €/kg. Running the search algorithm, this price is found to be **3.68 €/kg**.

Figure 38 - Hydrogen price of 3.68 €/kg returns similar profits for an all electricity and all hydrogen systems



The figure shows that in this case, the maximum occurs at either an all electricity solution, or an all hydrogen solution, with all solutions in between returning sub-optimal results. This case results in a lower hydrogen price (3.68 €/kg) compared to the previous case (4.36 €/kg). This is explained by the fact that the assumed flat price of 40 €/MWh is lower than the day ahead market prices (average about 60 €/MWh in 2029) and constantly below the cut-in price of some 70 €/MWh leading to lower costs and higher operating hours.

5.2 General sensitivities

Results show that the hydrogen price is of considerable importance for all scenarios, given the total spread of a factor 4 between the assumed low case of 1.5 €/kg and high case of 6.0 €/kg. The general results show that just by changing the hydrogen price to one of the two extremes, the qualitative outcome of scenarios changes completely. This cannot be displayed in the general sensitivities because of their limitation to a +/- 50% parameter deviation and the interrelation between day ahead electricity market prices and assumed hydrogen market price. Therefore, most of the results are presented twice, once based on the low hydrogen price and a second version based on the high hydrogen price.

The sensitivity analysis for other key parameters has been implemented on the complete range of scenarios, i.e. scenarios with conversion of electricity into hydrogen at an onshore location (Scenario 1 and 3), or at an offshore location (Scenario 2 and 4). Results shown in are specific for the dedicated onshore and offshore scenarios to obtain a general overview. The outcomes show a high sensitivity for the efficiency of the electrolyser, the OPEX electricity, the general scaling factor, and financial key figures such as the WACC and inflation.

More specifically, change of electrolyser efficiency turns out to be the most sensitive parameter. However, it has still to be determined to what extent electrolyser technology can still improve from the assumed ~75% HHV (some 52.48 kWh/kg) towards the actual HHV of hydrogen (some 39.49 kWh/kg). Some 80% seem to be possible in future (Energy Brainpool, 2018) which would already have a large impact on the NPV.[31]

Nevertheless, in the offshore hybrid scenario we observe that the higher the volume of electrons converted into molecules the more the electrolyser efficiency is improved. Negative effects of the electrolyser efficiency are compensated by a lower hydrogen production and instead more electricity being fed in the onshore grid. The impact of efficiency decrease is much smaller for the hybrid scenarios as the cut-in electricity price decreases with lower efficiencies and more electricity is monetised as a result.

Second, the costs of electricity have a significant impact on the business case of all scenarios. The OPEX of electricity considers all electricity costs: costs of electricity from the WP and the market used for conversion to hydrogen as well as costs of electricity generated by the wind park but fed-in the onshore grid instead of the P2G plant. Given the larger volume of electrons converted into hydrogen, dedicated hydrogen scenarios (Onshore Hydrogen & Island Hydrogen) are more affected by an increase or decrease in the electricity price than scenarios which can benefit from higher electricity prices (Onshore Hybrid & Island Hybrid). The electricity price in these first two scenarios are mainly based on the levelised cost of offshore electricity production, based on 40 €/MWh LCOE of offshore wind, highlighting the importance of continuing the technological improvement in the field of offshore wind. The hybrid scenarios are less affected by the cost development of offshore wind, but instead strongly depend on the price development on the day ahead electricity market.

The scaling factor affects various cost parts of the system by reducing the investment costs for: the electrolyser system, compressor station, and water treatment equipment. The outcome shows that scaling benefits contributes significantly to a successful P2G business case, but depends strongly on the extent to which they will apply to future large-scale P2G projects. The general scaling factor has a relatively higher effect on the low-price scenarios, since costs have a proportionally higher share in the NPV in these scenarios. To illustrate the impact of scaling: in the range used for the business case analysis, CAPEX levels of electrolysers came down from some 900 €/kW to about 350 €/kW (scale factor of 0.8).

[31] Given a hydrogen price of 6.0 €/kg and an increase of the efficiency to 80% HHV in the Island Hydrogen scenario, the NPV increases by some 20%.

Figure 39 - General sensitivity exemplary shown for scenarios Onshore hydrogen (left) & Island hydrogen (right) given a hydrogen price of 6 €/kg

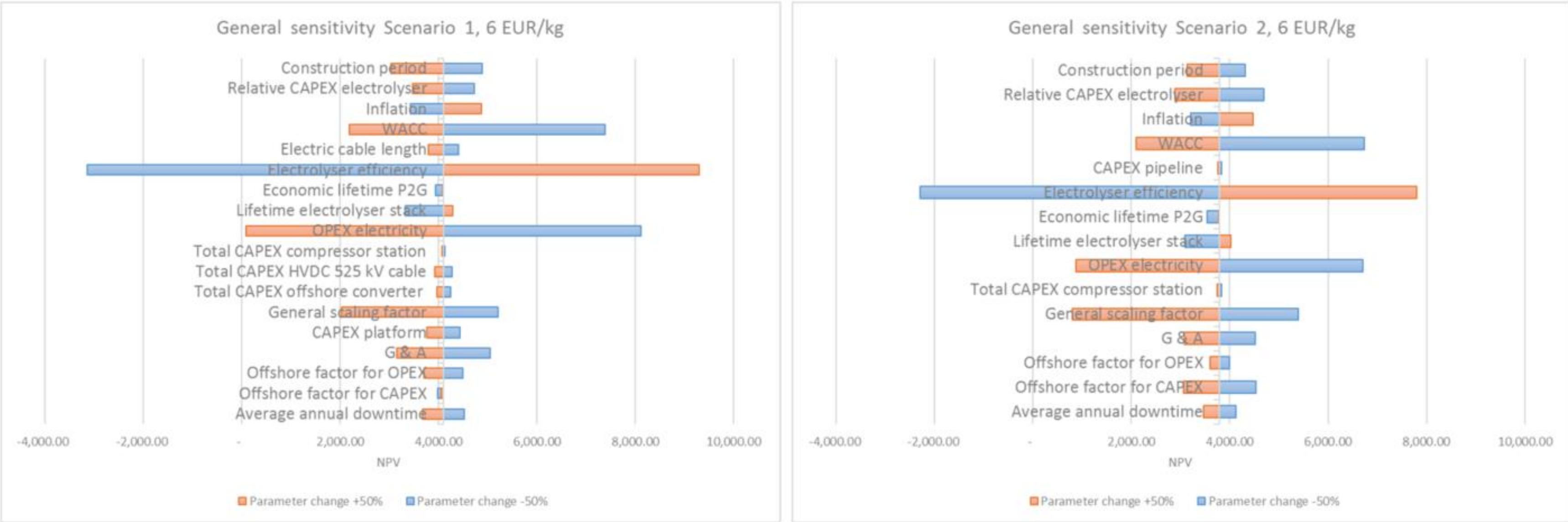
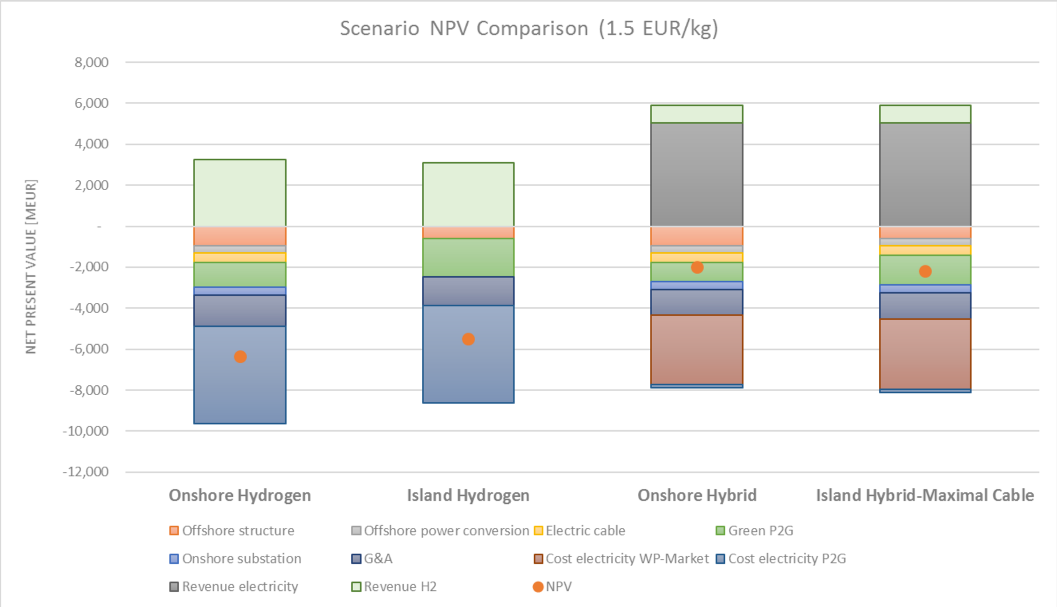


Figure 40 - NPV composition and comparison between scenarios based on a hydrogen market price of 1.5 €/kg



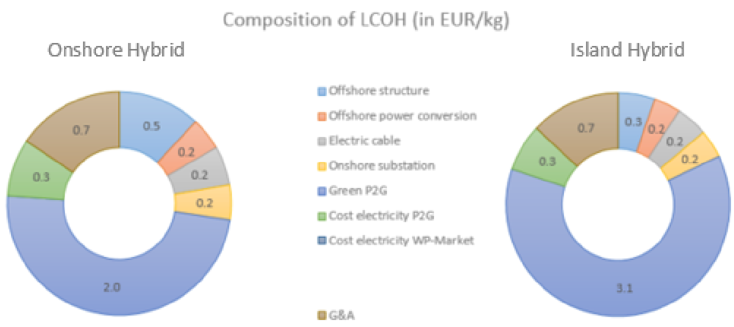
5.3 NPVs and their underlying components - Low hydrogen price case

shows the NPVs of each scenario assuming a low hydrogen price represented by an orange dot (note that all NPVs are negative). The composition of the NPV is visualised by the expenditure and revenue columns for each business case component. Negative columns represent the net present value taking into account both CAPEX (equipment, replacement of electrolyser stack) and OPEX. Positive columns represent the net present value of hydrogen and electricity sales.

What can be generally observed from the results is:

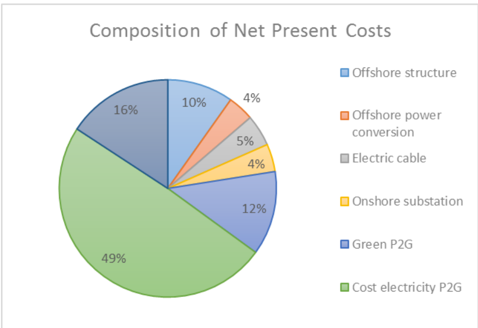
- The more the scenarios allow for electricity being monetised as such, the more positive the NPV becomes. This is why both hybrid systems turn out to have the highest NPV. What one can observe is that these scenarios have even a similar NPV despite the different cost components. The reason can be found when comparing larger costs for the offshore substation on a platform versus allocated island costs (difference of some net -360 MEUR) and on the other side lower onshore P2G equipment costs and savings on the pipeline infrastructure (both account for -520 MEUR net).
- Looking at the revenue side, in the hybrid Scenarios 3 and 4 most revenue is generated from electricity rather than hydrogen. Hydrogen accounts just for some 15% of the net revenue, basically occurring only in times of low electricity prices (below about 30 €/MWh). The load factor of the P2G system is with around 20% therefore rather low. The levelised cost of hydrogen is also with about **4.2 - 5.1 €/kg** the lowest in the hybrid scenarios due to the low load factor and consequently low electricity OPEX. Looking at the largest cost component being the cost of P2G equipment, one can observe the effect of the offshore cost factor which increases the LCOH by about 1.1 €/kg.

Figure 41 - Comparison of the LCOH composition between Scenario 3 and 4 (hydrogen market price=1.5 €/kg)



- When comparing the dedicated hydrogen scenarios instead (Onshore Hydrogen & Island Hydrogen) the NPV is far from break-even. This is mainly due to the large difference between hydrogen market price (1.50 €/kg) and the calculated LCOH's of about 5.3 and 5.6 €/kg of hydrogen.
- The main drivers of the LCOH in the dedicated hydrogen scenarios are the electricity costs which account for about 50% of the net present costs (). Capital and operational costs for P2G equipment follow with some 10-20% share in net present costs, the offshore structure (substation on platform/island) and G&A costs. Those costs cannot be recovered over the project period even though a net hydrogen quantity of some 1.6-1.7 Mt is produced in comparison to about 500 kt in the Scenarios 3 and 4, but again against a too low hydrogen price for economic production.

Figure 42 - Exemplary composition of net present costs (Onshore Hydrogen, 1.50 €/kg hydrogen price)

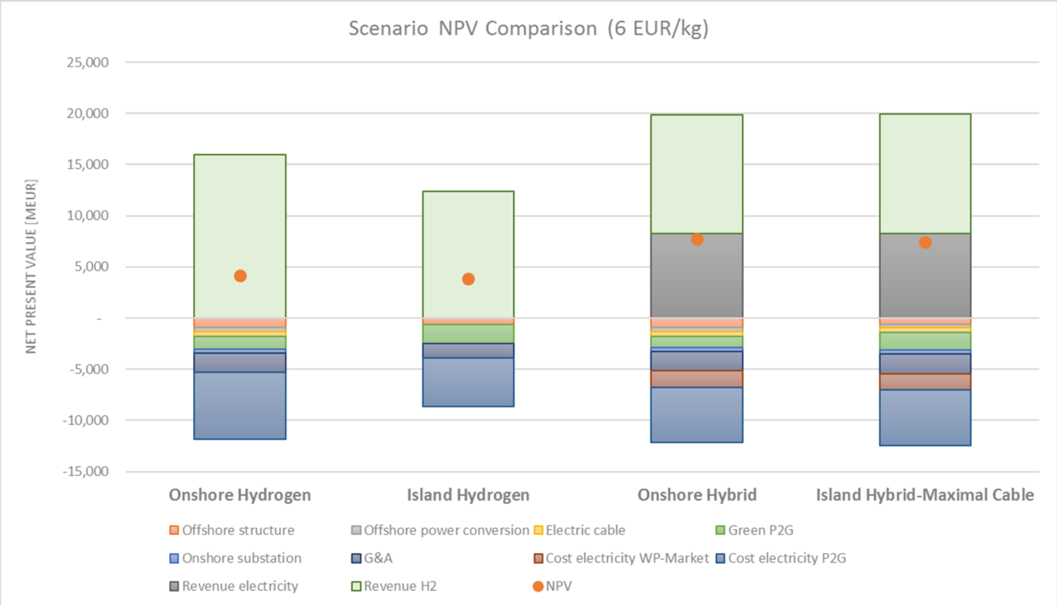


- Looking at the P2G operation, one can observe a high load factor of up to 70% (about 6,100 full load hours) in the dedicated hydrogen scenarios where there is no direct connection between wind park and electricity market. All electricity from the wind park is converted to hydrogen, however, with electricity costs exceeding the revenues of hydrogen, capital costs cannot be recovered. Therefore, the NPV is negative.
- In contrast hybrid scenarios with a very low load factor of up to 20% (about 1,800 full load hours) achieve a positive NPV, mostly due to revenues from WP electricity sold directly to the market.

5.4 NPVs and their underlying components - High hydrogen price case

Figure 43 shows the scenario NPVs and their composition assuming a hydrogen market price of 6.0 €/kg.

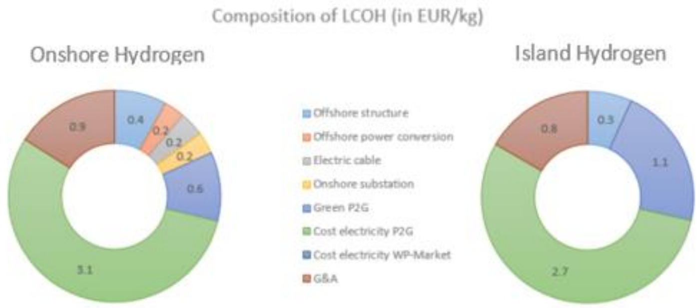
Figure 43 - NPV composition and comparison between scenarios based on a hydrogen market price of 6.0 €/kg



The results can be summarised as follows:

- In comparison to the previous observations, all scenarios return a positive NPV. In this case, the hybrid scenarios (Onshore Hybrid & Island Hybrid) result in the highest NPV. The Onshore Hybrid scenario shows advantages in lower costs for P2G equipment which outweigh the higher costs for an offshore substation on a platform compared to an island. In total this results in an about 290 MEUR higher NPV compared to scenario Island Hybrid-Maximal Cable.
- The revenue stream of the hybrid scenarios is evenly distributed between hydrogen and electricity sales. One can observe here a benefit of dual systems where during periods of sufficiently low electricity prices (electricity cut-in price of about 100 -110 €/MWh) hydrogen is produced, whereas high electricity prices are monetized as such. The steep increase of electricity price of on average ~58 €/MWh (2029) to ~210 €/MWh (2050) leads to high revenues from monetized electricity sales.
- Another interesting observation is that in contrast to the project NPV, the lowest LCOH occurs in the dedicated hydrogen scenarios (Onshore Hydrogen & Island Hydrogen) with 5.3 and 5.6 €/kg respectively () compared to 5.8-5.9 €/kg in Scenarios 3 and 4. Again, this is due to on average lower 'fuel' prices of constant 40 €/MWh electricity due to a direct connection between WP and P2G compared to higher DA-market based electricity prices.

Figure 44 - Comparison of the LCOH composition between scenario Onshore Hydrogen and Island Hydrogen (hydrogen market price=6.0 €/kg)



- Comparing both dedicated P2G scenarios, the offshore scenario shows a lower LCOH. Lower costs of the energy island compared to a conventional offshore substation on a platform, as well as no occurring costs for cabling and large power conversion equipment drive down the costs for the dedicated offshore case and outweigh the impact of larger offshore P2G equipment costs. In contrast, less revenue is generated from selling hydrogen due to the missing connection to the onshore grid. This results in an about 20% lower hydrogen production (comparing Offshore Hydrogen to Onshore Hydrogen) therefore less income. But as mentioned before, the additional revenue from hydrogen sales does not outweigh the net present costs of more equipment (power conversion equipment onshore and offshore) as well as the difference in island vs platform costs. The savings in capital and operational expenditures compared to the Onshore Hydrogen scenario still translate to a 0.3 €/kg lower LCOH and an about 310 MEUR higher NPV of Island Hydrogen. One has to state here though, that still the hybrid scenarios are superior in terms of project NPV.

5.5 Specific sensitivities

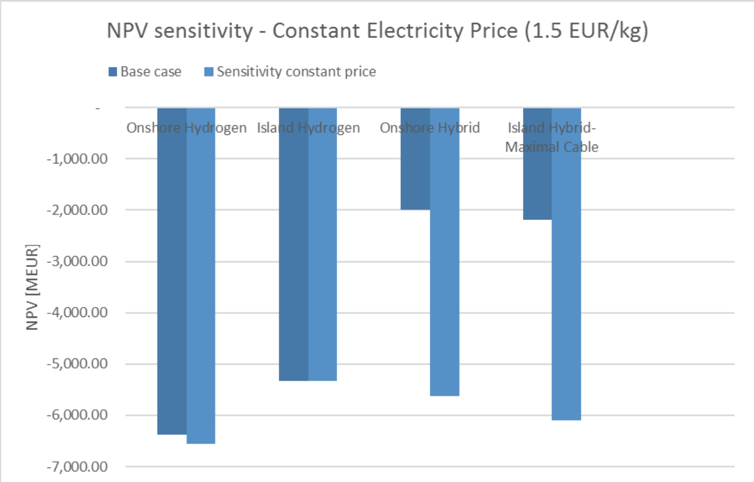
5.5.1 Flat electricity price

As indicated in the general sensitivity analysis, the NPV of any scenario is very sensitive to the underlying assumptions relating to electricity prices as they impact the business case on two sides: the operational expenses of the conversion system and the revenues from electricity sales when a hybrid system is considered.
This specific sensitivity analysis of changing the DA-based electricity price profile to a constant flat price of 40 €/MWh for all scenarios gives some insight in its benefits and disadvantages for both approaches. It is important to keep in mind, that the dedicated P2G scenarios (Onshore hydrogen and Island Hydrogen) are already based on the same flat electricity price due to a direct single connection to the WP, with the exception that the onshore Scenario 2 has additionally the opportunity to receive electricity from the market based on DA-pricing.

The 1.5 €/kg base case is based on the electricity price profile supplied by CE-Delft with a mean price of about 60 €/MWh in 2029 and 2050. However, prices vary strongly potentially opening opportunities for operating the P2G system during times of low prices and selling electricity in times of high prices.

Changing the variable electricity price profile to a constant price has different effects on: a) the dedicated P2G scenarios Onshore Hydrogen and Island Hydrogen, and b) the scenarios Onshore Hybrid and Island Hybrid shown in Figure 45.

Figure 45 - Sensitivity - Constant electricity price (1.5 €/kg)

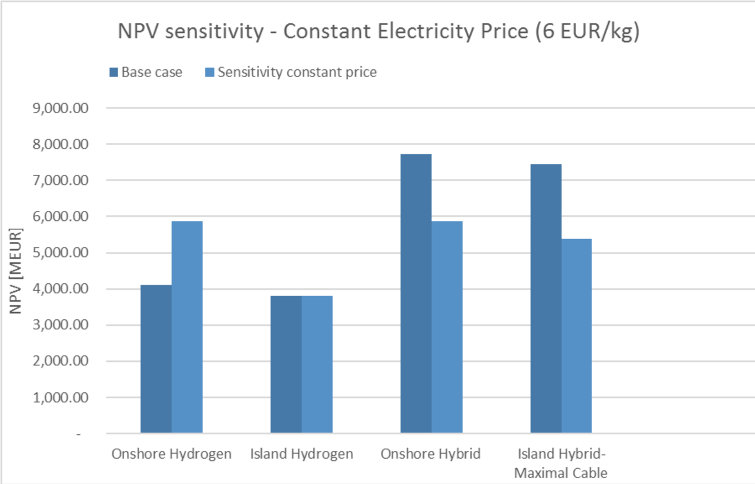


a Scenario Island Hydrogen is not affected by the sensitivity since in the base case also a constant bilaterally agreed price apply. It shows a minor effect on scenario Onshore Hydrogen where already constant pricing is applied to the electricity sourced from the WP. The only difference is here that next to the electricity sourced from the WP also no use can be made of the onshore electric connection and periodically low electricity prices given the constant price sensitivity. As an effect the P2G plant does not take any additional electricity from the market (initially some 7,100 GWh) causing the NPV to decrease to a small extent and the **LCOH to increase** from the initial 5.6 €/kg to some 6 €/kg.

b The hybrid scenarios consider only hydrogen production when market prices are below a certain threshold (electricity cut-in equals here about 30 €/MWh). As the flat price of 40 €/MWh always exceeds the target price, the P2G plant does not operate at all and the generated electricity generated by the WP is completely fed in the onshore electricity grid. The applicable electricity price of 40 €/MWh is however on average about 20 €/MWh lower than the DA-market price and therefore the NPV of the hybrid scenarios decrease significantly.

A similar analysis is conducted for the 6.0 €/kg case. This case originally considers the electricity price profile supplied by CE-Delft with a mean price of about 60 €/MWh (2029) and ~210 €/MWh (2050).

Figure 46 - NPV sensitivity on constant electricity prices (6.0 €/kg)



Similar to the previous case, the change of electricity prices based on the day ahead market to a constant price has two main effects:

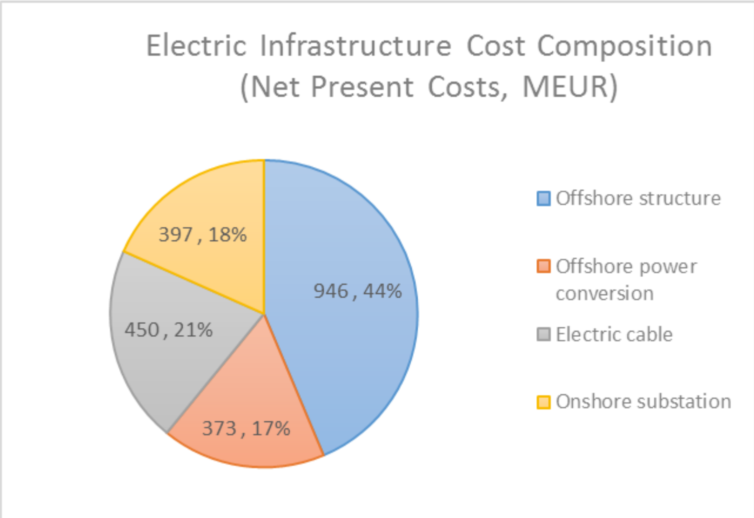
a First, scenario Island Hydrogen is again not affected by any changes in the electricity market price as the electricity costs in the base case are also based on a fixed constant levelised cost of offshore wind. This is also true for scenario Onshore Hydrogen, though in this case the electrolyser can retrieve extra electricity from the onshore grid when the WP generation is not sufficient to satisfy the full P2G capacity, and when given electricity price is below the electricity cut-in price (in this case some 100-110 €/MWh). Since the constant price of 40 €/MWh is way below the cut-in price, the P2G plant operates as much as possible with the aid of the onshore grid. This results in an extra ~60% of available electricity and increased production of hydrogen from 1.7 to about 2.5 Mt. The **LCOH improves** consequently from some 5.7 €/kg to some 5.2 €/kg.

b Second, also in the hybrid scenarios one can clearly observe that the P2G plant almost operates with a 100% load factor since the electricity costs are constantly lower than the cut-in price of 100-110 €/MWh. This leads to a reduction in the LCOH of about 0.6-0.7 €/kg. The NPV decreases at the same time, since electricity is not fed in the onshore grid anymore and therefore does not return any revenues.

5.5.2 Internalisation of electric infrastructure externality

Savings on the electric infrastructure can reduce the economic burden that will be placed on society. From a system perspective, these costs should be internalised to make a fair comparison between the various alternatives. All scenarios except of scenario Island are not affected by internalisation of this externality, as they have a full electric connection.
The importance of this consideration is partly reflected by showing the calculated cost of a conventional fully scaled 1.9 GW high-voltage DC system resulting in a net present cost of about 2.2 billion EUR consisting of the offshore structure (platform), the offshore power conversion equipment on the platform, the cabling and the onshore substation as shown in:

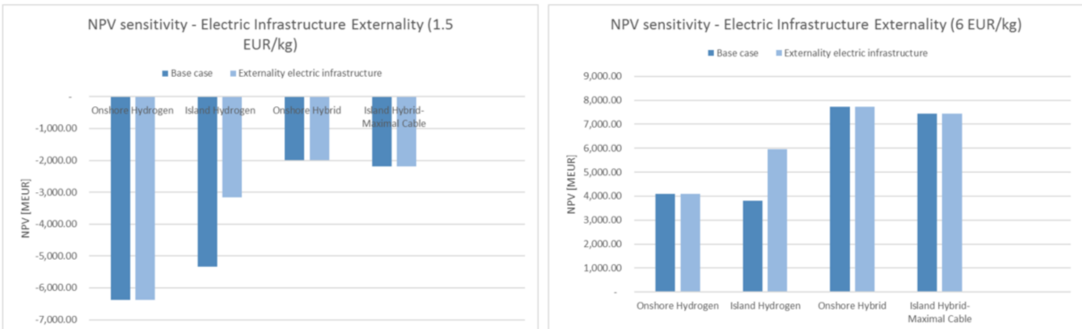
Figure 47 - Composition of electric infrastructure NPC (Onshore Hydrogen & Onshore Hybrid)



To show the potential impact of the externality, the avoided investments are internalised by reducing the Net Present Costs (NPC) of the scenario Island Hydrogen by the NPC of the electric transmission infrastructure of about 2.2 billion EUR.

The effect of the internalisation is depicted in . The results show the large impact on the NPV. At the same time, the lowest LCOH is also reached in this scenario with a reduction of about 1.3 €/kg to an LCOH of 3.9 €/kg.

Figure 48 - Sensitivity infrastructure externality

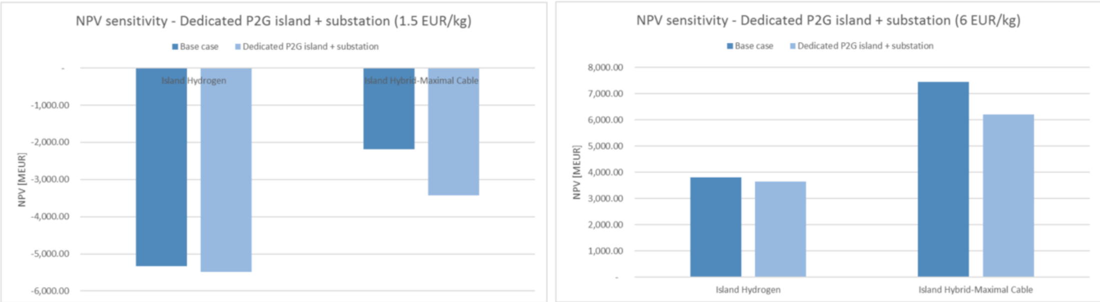


5.5.3 A dedicated power-to-gas island and separate substation

We consider a multifunctional island of which the investment costs are about 685 MEUR/GW. In the assessment of the energy system only the costs related to the share of the area used for power-to-gas and onshore grid connection are allocated, assuming costs are divided amongst multiple users. An alternative to the multifunctional island is a stand-alone power-to-gas island, which is a less costly option as such comparing total costs of 570 MEUR (285 MEUR/GW) compared to 1,370 MEUR (685 MEUR/GW). However, for both relevant offshore power-to-gas scenarios the NPV turns out to be more negative (Figure 49) due to the following reasons:

- The distribution of island CAPEX and OPEX to multiple users results in total lower costs for the P2G and offshore transmission system operator. For the P2G system operator only the relative CAPEX increases by about 270 MEUR per GW when switching from a multipurpose island to a dedicated island.
- Since a dedicated P2G island does not have sufficient space to host in addition an offshore substation for power conversion and transmission, we assume in this sensitivity analysis that in the scenario Island Hybrid – Maximal cable a separate offshore HVDC substation is required. Results show that as an effect of the NPV of Scenario 4 is reduced by some 1.2 billion EUR.
- The sensitivity translates into an about 0.8-1.9 €/kg higher LCOH.

Figure 49 - Sensitivity infrastructure for stand-alone islands (hydrogen market price of 1.5 €/kg (left) & 6.0 €/kg(right))



6 Non-technical aspects and risk assessment

Whereas the previous chapters deal with the techno-economic analysis of the island, this chapter focuses on the non-technical and integration aspects. It is a first overview. As the development of the multifunctional island progresses, many aspects need to be studied in further detail. This chapter should therefore be seen as a starting point of further exploration of non-technical aspects relevant to the development of the energy island at IJmuiden Ver.

This chapter consists of three sections. The first section provides an overview of the main non-technical and integration aspects. The second section is a SWOT analysis. The last section summarises the findings of the interviews with relevant stakeholders, a meeting with a number of relevant parties, experience from the contacts of OSF and literature reviews. The list of interviewed stakeholders can be found in Appendix F.

6.1 Key non-technical and integration aspects

The North Sea is one of the busiest seas of the world with many uses and functions. It is a highly regulated part of the world, with numerous stakeholders and stakes. The energy transition is a process of transforming the energy system from fossil-based to zero-carbon. For Northern Europe, the North Sea plays a key role for this transition. It offers opportunities for large-scale wind energy and hydrogen production. The development of a multifunctional artificial island for the infrastructure needed to convert, (inter-)connect and transport the energy seems a promising way forward for the large-scale exploitation of wind energy in the North Sea. In addition, an island can play a major role in the maintenance of the wind turbines and electrical installations and other sustainable activities at sea such as aquaculture. The island could be of benefit for various activities in the North Sea. It could help to develop a North Sea-centred reliable carbon free energy system. The realisation of multifunctional energy islands is dependent on many non-technical aspects. In the following text we highlight legal, policy, ecological, stakeholder, and international aspects.

6.1.1 Legal Aspects

Construction and operation of a multifunctional artificial island is subject to a large number of laws and regulations. We focus on two aspects key to the multipurpose artificial island: the legal framework that determines the jurisdiction for the construction, operation and dismantling of an artificial island, and the rules and provisions relevant for the generation, transportation and sale of hydrogen.

Construction, operation, and dismantling of an artificial island

A key legal framework for operations at sea is the United Nations Convention on the Law of the Sea (UNCLOS). The UNCLOS describes the internationally broadly accepted set of rules for the use of the seas and the oceans, the extraction and use of natural resources, and protection of the marine environment.

The UNCLOS defines different maritime zones where coastal states, *in casu* the Netherlands, have certain jurisdictional powers. The envisaged location of the artificial island at IJmuiden Ver falls in the Dutch Exclusive Economic Zone (EEZ). The EEZ extends up to 200 nautical miles from the coast.

The UNCLOS does not have a definition of an artificial island. It does however regulate their construction and operation. Article 55 of the UNCLOS states that "*the coastal state has jurisdiction as provided for in the relevant provisions of this convention with regard to the establishment and use of artificial islands, installations and structures*" (UN General Assembly, 1982). The coastal state — the Netherlands — thus has the jurisdiction to authorise the construction and use of a multipurpose artificial island at the IJmuiden Ver area.

The UNCLOS is not the only law regulating the development of an artificial island. Also European and national laws apply. In particular, if the development of the artificial island would be commissioned by a governmental body, or a government-regulated party such as TenneT, European law requires it to be tendered on a European level.

Relevant national laws to build an artificial island include permits in accordance to the Water Act, Environmental Management Act, Spatial Planning Act and Environmental Protection Act. The ministry of Infrastructure and Water Management Innovation and the ministry of Economic Affairs and Climate Policy are the responsible authorities. Permitting decisions weigh, amongst others, factors such as the necessity of an island and its the impact on nature.

Once an artificial island has been constructed, Article 60 (Art. 2) of the UNCLOS states that "*the coastal state shall have exclusive jurisdiction over such artificial islands, installations and structures, including jurisdiction with regard to customs, fiscal, health, safety and immigration laws and regulations.*" (UN General Assembly, 1982). The Dutch state is thus the authority exerting jurisdiction over an artificial island if it is built in the IJmuiden Ver location. If an artificial island is built further offshore, such as on the Doggersbank, depending on the exact location, the authority is to be exerted by the Netherlands, the United Kingdom, Germany or Denmark (Government of the Netherlands, 2020a).

Finally, Article 60 of the UNCLOS also stipulates that an artificial island that is no longer in use needs to be dismantled. This stipulation is relevant for the planning and techno-economic assessment of the artificial island.

Production, transportation, and sale of hydrogen

Production of hydrogen from wind power is at the heart of this stud. To achieve this, cable connections between the island and the offshore wind farm are required. In addition, depending on the system design, cable connection with the onshore grid are also required (see previous chapters). Currently, TenneT has no mandate to connect wind farms with other infrastructures on the North Sea. TenneT can only connect wind farms with the electricity grid on shore. However, an electrical connection between the wind farm and the island is indispensable for the generation of hydrogen.

Once hydrogen is produced on the island, it needs to be transported to the shore. Currently the Dutch Gas Act does not include any dedicated provisions to support the development of an energy system — and infrastructure — in which hydrogen plays a major role (Government of the Netherlands, 2000). System operators do not currently have a clear mandate to transport hydrogen, and thus to build hydrogen pipelines, or refit existing natural gas pipelines for hydrogen transportation. This lack of legal directive leads to uncertainties and can increase risk for investments.

Finally, current legislation limits certain applications of hydrogen. Dedicated hydrogen infrastructure exists only in industry clusters. Mixing hydrogen gas with natural gas is only allowed to a very limited extent (0.02 mol% in the national grid) (Dutch Parliament, 2019). In addition, existing legislation results in restrictions for use of hydrogen in existing equipment. These issues are not specific to the multifunctional island at the IJmuiden Ver location, but leads to uncertainties for the development of the future demand and market for hydrogen.

6.1.2 Policy perspective

Long-term policy perspectives shape the legal framework of the future. Both the Dutch Climate Agreement and the Negotiators Agreement for the North Sea are of particular importance for the role of hydrogen and its production on the North Sea.
The Climate Agreement considers hydrogen to be a key energy carrier: as a feedstock for industrial processes, and a means to balance the variability of renewable resources. Given the large potential for wind power generation on the North Sea — the so-called Green Powerhouse on the North Sea — and the anticipated increase in electrolysis capacity, the Climate Agreement underscores the potential of linking of wind power and hydrogen generation (Government of the Netherlands, 2019).

In line with the Climate Agreement, the Negotiators Agreement for the North Sea on the future uses of the North Sea endorses the importance of renewable energy generation on the North Sea (Consultative Body for the Environment, 2020). The Agreement leaves room for the development of artificial islands, and for the generation of hydrogen on the North Sea. However, concrete plans for both still need to be developed.

Thus, although electrolysis and hydrogen generation, including on the North Sea, are generally seen as important factors in the energy transition, an overarching policy vision for the development of artificial islands for these purposes is currently lacking. As of the time of writing, the national government has not started issuing permits for artificial islands. The government expects such islands to potentially become relevant only after 2030. For the IJmuiden Ver area specifically, the minister of Economic Affairs and Climate Policy has announced that the wind energy winning area around IJmuiden Ver will be connected by two 525 kV DC cables. Platforms will be used for this connection (Ministry of Economic Affairs and Climate Policy, 2019).

Finally, another important aspect of the policy vision, is the reuse of existing pipelines for transportation of hydrogen and CO_2. In certain parts of the North Sea, such as in the IJmuiden Ver area, the number of pipelines is limited. Thus, transportation of CO_2 for CCS storage under the North Sea, and the transportation of hydrogen generated on the North Sea could compete for the same infrastructure. Clear policy choices are needed on the decision criteria for scarce infrastructure.

6.1.3 Ecological aspects

An artificial island can have substantial impacts on the existing seabed and its ecosystem. The North Sea is an important marine ecosystem, with many parts marked as Natura 2000 protected areas. The Southern part of the IJmuiden Ver area is currently not a Natura 2000

protected area, but is considered for future protection (Government of the Netherlands, 2020).
The ecological impact of an artificial island depends on the specifics of the island which are still in development. Even when artificial islands have a limited negative impact of the local environment, their role in the transition to sustainable energy generation can outweigh these effects. The consortia working on the design of artificial islands aim for a “building with nature” approach. This approach combines embracing the dynamics of the natural environment with provide opportunities for improving marine nature. The latter could be further explored as the design and development of the island takes further shape.

Currently, nature conservation organisations indicate that knowledge on the impact of artificial islands on the marine environments is lacking. The impacts on birds, aquatic organisms, benthic organisms, as well as sea currents and the sea floor itself are insufficiently known. Both in the construction phase and in the operational phase the impacts on the sea, sea floor, and sea life should be studied, assessed and mitigated. Planning, construction, and operation of the island requires further collaboration with scientists, such as marine ecologists. A pilot could bring more information about all this impacts.

6.1.4 Stakeholder aspects

Hydrogen production on the North Sea could be part of a future sustainable energy system where hydrogen is a major energy carrier. A multipurpose island in the IJmuiden Ver area could become a stepping stone towards such a future energy system.

Transforming the existing energy system into a future sustainable energy system requires a coordinated collaboration between a broad range of stakeholders. Key stakeholders are wind farm developers and operators, system operators, gas and oil industry, onshore industry, fisheries, the national government, and nature protection organisations.
The national government is a key stakeholder as the energy transition is a national interest. The national government can play a coordinating role through, for instance, a clear policy vision. This aspect has been addressed earlier. The nature protection organisations represent the ecological aspects, which also have been described above.

Wind farm developers and operators, gas and oil industry, and system operators are all stakeholders within the energy system. Hydrogen generation on the North Sea requires particular coordination and cooperation between these parties. First, for hydrogen generation on the North Sea to be economically sound sufficient wind power capacity needs to be available which is not or cannot be directly transported to shore. Yet, this is not a sufficient condition. Both the electrical power and hydrogen gas need to be transported. This requires coordination with TenneT, GasUnie, and the gas and oil industry, but also with the onshore industry as the latter is a consumer of hydrogen, and an emitter of CO_2, which could also be transported through existing natural gas pipelines for storage under the North Sea.

Lack of central coordination could create a chicken-or-the-egg problem. For instance, steel production is currently a large source of CO_2 emissions. The pipeline landing in Beverwijk could be used to transport CO_2 for storage under the sea floor. Yet, if hydrogen would be abundantly available, steel can be produced using hydrogen as a reducing agent instead of coal, thus avoiding CO_2 emissions all together. This would however require considerable adaptations of the steel factory. Both hydrogen and CO_2 could be transported the same pipeline landing in Beverwijk, yet not at the same time. Thus, a clear and timely vision for reuse of the pipeline is necessary to enable the transition. In either case, the pipeline can only be reused if it is no longer used to transport natural gas.

Uncoordinated choices by stakeholders away from their current operations pose large risks for them individually. Coordination could be achieved through dialogue between the various stakeholders, and/or through a centralised vision by the national government. First steps could be taken as a joint effort involving both market and public parties. The Negotiators Agreement for the North Sea has created an important platform for such a collaboration. Noteworthy is the current absence of a dedicated 'energy island stakeholder' within the consultative body of the North Sea Agreement. As artificial islands are new, these interests are not fully represented yet.

Another important group of stakeholders are fisheries. They are not directly part of the energy system but have high stakes in the use of the North Sea resources. Existing fishery stakeholders can view a new artificial island as a threat to current fishing grounds. Yet, an energy island could also create an opportunity to make fishing more sustainable. Highlighting the opportunities over the threats requires an open dialogue and clear communication. The multifunctional energy island could be used for refuelling trawlers closer to fishing grounds (which are even further offshore than the IJmuiden Ver area). In addition, storage and regular joint transportation of the fish to shore is can be another key benefit for fisheries as it would allow the fishing trawlers to stay closer to the fishing grounds for longer periods of time.

6.1.5 International aspects

As the energy system becomes more complex, with more variability and uncertainty, closer international interconnection could help balance the electricity system. While gas fields in the North Sea have been largely developed following national interests and within national boundaries, the future energy system could be more internationally interconnected. Collaboration on strategic areas across countries in the North Sea region already exists (North Sea Region, 2020).

A multifunctional island could be a first step towards a more integrated regional collaboration for an efficient, interconnected and sustainable energy system (Gorenstein Dedecca, et al., 2018). As national visions are still in development, the opportunities need to be further researched and actively pursued.

6.2 SWOT analysis

The following SWOT analysis is based on key aspects of the proposed multifunctional island (as described in Chapters 1 through 3) and the analysis of non-technical aspects above. It should be seen as a first step towards a holistic risk assessment.

	Strengths	Weaknesses
Internal	– **Showcase for future projects.** Getting ahead with experience in energy island building and operation (pilot) – **Financial benefits through reuse of existing pipelines.** Transportation of large amounts of energy a gas is cheaper than as electricity (TNO, 2018). In addition, reuse of pipelines largely avoids decommissioning costs.	– **Dependence on permitting.** The construction of the energy island is contingent on permits from the Dutch government. Currently, platforms are being permitted. – **Dependence on an uncertain future system and transition path**. The energy island is a piece of an energy system puzzle in which hydrogen plays a major role. The vision for

	Strengths	Weaknesses
	– **Easier maintenance and operation.** Building and maintenance base on an island is easier than on a platform. – **Integration of diverse functions.** Combination of conversion and transportation of energy with accommodation for offshore workers, support for construction and maintenance of offshore wind farms, aqua culture (Seaweed) and for fisheries.	such a system and a transition path towards it are currently missing. – **Short timeframe.** The project has an ambitious planning, which, given existing permitting and future system uncertainties, is a weakness.
	Opportunities	**Threats**
External	– **Possible energy system changes due to covid-19 crisis.** The ongoing covid-19 crisis has significant impact on the gas and oil industry. The outcome is yet uncertain. The crisis can become an opportunity for an accelerated transition to a sustainable energy system, where hydrogen is a major energy carrier. In this scenario, the crisis is an opportunity for a rapid development of a pilot energy island in the IJmuiden Ver area, which then could become a stepping-stone for the further transition of the energy system. – **Better interconnection of international energy systems.** The IJmuiden Ver area is close to the Exclusive Economic Zone of the United Kingdom. This proximity opens up opportunities for transnational integration of energy systems, whereas current energy systems infrastructure, in particular North Sea pipelines, is predominantly nationally focused. –	– **Possible energy system changes due to covid-19 crisis.** The covid-19 crisis could become a threat to the project as well. The impact on the gas and oil industry leads to very tight margins and revenue losses. Financial hardship could be a threat to, amongst others, the possibilities for the reconfiguration of pipelines for both hydrogen and natural gas transport. – **Continued use of pipeline for natural gas or reuse for CO_2 transport.** One of the key strengths of this project is the reuse of pipelines. It is contingent on the availability of said pipelines before 2030, which in turn depends on the evolution and choices for the entire natural gas infrastructure in the North Sea. It is unclear yet which wells will be decommissioned at which point in time, which pipelines will still be used for natural gas, and which would be reused for the transportation of CO_2. – **Price of hydrogen**. The price of hydrogen is critical for the business case of this project. The future price of hydrogen is dependent on many factors shaping supply and demand of hydrogen. – **Lack of support by existing North Sea stakeholders.** The North Sea is one of the busiest seas in the world, with many stakeholders. Absence of an energy-island representative at the table for North Sea Agreement is a potential threat to the interests of a future energy island, and its realisation.

6.3 Discussion of the non-technical analysis

The IJmuiden Ver energy island has the ambition to become a demonstration project in the North Sea. It focuses on an energy system that does not yet exist. Its trailblazer's ambition is a strength and can be of importance to yield future opportunities. At the same time, its realisation is subject to threats from an existing system which is not (yet) entirely geared for the energy transition.

Many stakeholders and many issues (legal, policy, ecological, energy, and international, etc.) are at stake in case of the construction and exploitation of an artificial island in the complex environment of the North Sea. In policy documents and in communications with various parties, many of them indicate that artificial islands could play an important role in the energy system on the North Sea. This is the case both in the Netherlands and in other countries bordering the North Sea: Denmark, United Kingdom, Belgium, and Germany. As of yet, an artificial energy island is unchartered territory. It is therefore important to take into account as many interests as possible when developing the first island. This is a delicate process. Different parties involved have different interests. A balance must be found in the realisation of a sustainable energy system with innovations such as artificial islands and hydrogen production at sea, and protection of the marine ecology.

While the business case of a pilot project might not be entirely representative of full-scale far-offshore islands, the current legal, permitting, market and systemic issues are not entirely unique to the particular IJmuiden Ver area. Issues during the energy system transition period are expected not to be representative for the future energy system. Resolving these issues requires an overarching vision and plan shared by a wide group of stakeholders, including stakeholders with interests in the North Sea, such as wind park operators, gas and oil industry, fisheries, sea shipping, environmental protection organisations, as well as the national government (in particular the ministries of Economic Affairs and Climate Policy, and of Infrastructure and Water Management) and the onshore industry, network operators, and other energy system stakeholders. Although as a pilot this project is ambitiously large, from the systems perspective, it might be too small and not ideally located to tip the system.

The realisation of a first multifunctional island can only be successful if all stakeholders are taken on board. In addition to the techno-economical aspects and broader societal aspects addressed in this report, marine ecology aspects should be included in the further development of the island. Legal, policy and internationals aspects should be tackled together with the respective authorities, and used as a policy development tool. Sufficient time should be allocated to take the necessary steps in a stakeholders-friendly way.

7 Discussion and conclusions

The objective of this study is to assess the potential and feasibility of hydrogen generation on a multifunctional island at IJmuiden Ver area. Such an island could provide energy services, while taking advantage of reusing existing gas pipeline infrastructure in the North Sea. As such it could facilitate the transition to a decarbonised energy system. The economic returns of various scenarios of converting and bringing to shore wind power generated offshore are assessed. Two kinds of conversion of wind power generated offshore have been assessed using quantitative modelling and scenario analysis: power conversion for power transmission and power-to-gas conversion, i.e. generation of hydrogen using offshore wind power.

In the study four scenarios have been assessed, two with conversion on an island and two with similar conversion on shore. The scenarios specifically differ with respect to the degrees of freedom: in one set of scenarios all power is used to generate hydrogen, whereas in another set of scenarios (the hybrid scenarios) the operators face the choice to either use wind power to generate hydrogen, or transport to electricity to shore, eventually choosing an optimal ratio. Given these four scenarios various sensitivity analyses have been carried out, specifically also to assess the feasibility against different future projections of power and green hydrogen prices. With respect to the latter a range of 1.5 to 6 €/kg has been used for the 2030-2050 period; higher future green hydrogen prices may be conceivable depending on amongst others policies towards introducing green gases.

Modelling has been done using existing models and a newly developed dedicated spreadsheet model[32].

Recognising that engineering and economics will not be the only criteria in assessing the feasibility of multifunctional islands, various other factors have also been included in the assessment that have a profound impact on the feasibility of a multifunctional island, including: legal, ecological, and policy aspects and also feature (international) stakeholder considerations.

7.1 Main findings from the techno-economic analysis

Below we summarise the answers to key questions raised and resolved in this report.

7.1.1 What type of structure?

In our analysis, three types of revetment structures or island solutions have been considered:

1. A ‘terp’-type island, this is a traditional sandfilled island to some six metres above MSL with a strong revetment consisting of rock and concrete elements and a seawall on top of the crest.
2. A ‘polder’-type island with a lower level of the island (around mean sea level) and a watertight revetment consisting of caisson type structures.

[32] For details on the model information can be requested from Malte Renz or Miralda van Schot via https://www.newenergycoalition.org/en/

3. An ‘lagoon’-type island with a low crested outer ring and lagoon or lake-like area in which a sandfilled island is constructed for the facilities, or with facilities floating on the sheltered lagoon.

Metocean and geotechnical conditions for the anticipated location of the offshore island are reported. The three types have been analysed in principle designs and first cost estimates leading to the conclusions. The three revetment types have been analysed in general terms. First cost estimates lead to the following conclusions. Construction costs for the terp and polder islands are similar. The polder-type island, in which a large number of caissons need to be transported and placed in offshore conditions is challenging and is depending on the weather. As such it forms a significant risk for planning as well as for costs. The lagoon-type island is some 10% more expensive in terms of construction costs as the rif revetment along the island is significant longer than a revetment along the edge of the island. The lagoon type island does give more options for a phased development of the island and possibilities of floating facilities.

For the island concept in this study, the terp type-island is preferred as it is likely to have the lowest costs and future (floating) development is not considered in the present alternatives.

7.1.2 Onshore or offshore hydrogen conversion?

The assessment of the feasibility of constructing an island in the specific conditions of this study shows that from a purely techno-economic perspective there is not much difference in terms of economic feasibility between converting wind power to hydrogen at a 2 GW scale on an offshore island or on shore, although the onshore (hybrid) option scores slightly better in Net Present Value outcomes. For the full hydrogen scenarios, the island option has a slightly higher NPV outcome, though negative, when the hydrogen price is 1.5 €/kg. With a hydrogen price of 1.5 €/kg all scenarios result in a negative NPV; and with a price of 6 €/kg all scenarios result in a positive NPV.

7.1.3 Convert to hydrogen or not?

The simulations from modelling and from sensitivity analysis suggest that the business case of converting offshore wind power into green hydrogen benefits from the following factors, irrespective whether conversion is on shore or offshore:
- Lower costs of capital (CAPEX electrolyser systems) on average benefit a conversion into hydrogen
- Lower future power prices also benefit the business case of hydrogen production
- This also applies if electrolyser CAPEX levels come down, electrolyser efficiency improves, and if green hydrogen prices increase with a growing demand for the commodity
- Inclusion of avoided system costs, such as balancing and grid reinforcement, in the valuation of green hydrogen production benefits the conversion business case

7.1.4 Hybrid system or full conversion?

A key question is whether wind energy offshore generated should be partially, entirely, or not at all converted to hydrogen depends predominantly on the electricity price and green hydrogen market price. These prices, especially the latter, also determine the optimal ratio between selling hydrogen, electricity or both.

This question is answered by analysing the island hybrid – optimal cable scenario. This scenario includes hydrogen generation on the offshore island and allows for flexibility in the installed hydrogen conversion capacity. The following tipping-points of hydrogen price values have been found at which it did not make any economic difference whether all power would transmitted to shore or be converted into hydrogen: about 4.0-4.5 €/kg for scenario with power prices based on the day ahead market, and in the range of 3.5-4.0 €/kg for the scenario with a fixed 2029 price of 40 €/MWh (see Section 5.1). These ranges indicate a window of opportunity at which a wind farm operator may hedge the risks of low electricity revenues by integrating flexibility from the power-to-gas system. Similarly, the P2G operator may hedge the risk of paying too much for the electricity. In fact, it turned out that as soon as hydrogen prices would rise to higher levels, the economically rational decision is to convert almost all wind power into green hydrogen.

The economics of the hybrid scenarios in which operators have degrees of freedom to determine the optimal level of hydrogen conversion turned out to be on the whole superior to the economics of the scenarios without such flexibility. This was the case even if the benefits of offering flexibility services to the electricity grid have not been included in the analysis.

7.1.5 Multifunctional or dedicated island?

The economic case for constructing an island to be used for energy conversion is on the whole more positive for a multifunctional island than for a dedicated P2G island. Island construction costs per GW installed conversion capacity are some 285 MEUR in the dedicated island case against some 230 MEUR in the multifunctional island case assuming costs for conversion will be in proportion to the area occupied.

Our modelling shows that, on the whole, the net present costs of renting/buying an appropriate share (about a quarter of the about 100 ha for a 2 GW handling capacity) of a multifunctional island, although considerable in themselves (about 600 MEUR), are relatively modest if compared to the total equipment net present costs involved with offshore energy production, conversion and transport of some 2.7 billion EUR.

A multifunctional island reduces the overall costs of energy conversion by about 1-2 €/kg of hydrogen compared to a situation with a dedicated P2G island and separate substation. Also, in our project circumstances the costs of AC/DC conversion turned out to be lower if included on an island, as compared to the conventional platform solution.

In the studied circumstances, the business case of creating a dedicated offshore hydrogen production island improved

- if larger amounts of hydrogen can be produced on the island;
- if hydrogen can be sold against higher prices;
- if avoided costs of the (offshore) electric infrastructure would be larger and could be internalised (see also similar results in (Jepma, et al., 2018) (North Sea Energy, 2020a)).

The benefits of opting for a multifunctional rather than a dedicated conversion island could be even larger, yet harder to monetise. A multifunctional island offers opportunities for various stakeholders through activities including energy, industrial, marine, and tourism options, and as well as ecological services.

7.1.6 Limitations of outcomes

The results in this study are based on the assumption of a multifunctional island connected to a wind farm of 2 GW and located to the north of IJmuiden Ver area for the year 2029. The outcomes cannot be generalised with respect to the following aspects:

- The investment cost of a multifunctional island have been analysed for a specified location. The investment and operational cost may alter when other functions or other locations are considered.
- The investment costs of reuse of pipeline and platform infrastructure have been specifically assessed for the LOCAL pipeline. Adapting the routing or location of a multi-functional island may alter the results.
- Changing parameters such as the power-to-gas capacity, wind profile and pipeline capacity might alter the results. The same is the case for the view year 2029. Selecting the year 2040 or 2050 as estimated time of completion most likely have results in a stronger decline in investment cost for electrolysers (global market learning) in relation to the decline for capital cost for HVDC systems. Towards 2040 and 2050 wind farms are be most likely to be further offshore resulting in other tipping points for electricity versus hydrogen.

7.1.7 Future considerations beyond the scope of this study

The business case of offshore hydrogen generation on an artificial island improves both absolutely and relatively in the following cases:

- If the size and the multifunctionality of the island increases allowing not only for more activities, but also for installing larger capacities than 2 GW.
- If the island is located further from shore allowing to benefit more from relatively cheap energy transport through pipelines.
- If pipeline infrastructure for transmission of hydrogen is readily available at close distance allowing for benefitting from the low cost transport options relatively easily
- If building an electricity cable landing point can be avoided by using or reusing pipelines.
- If public resistance and/or legal issues make it more difficult to install large onshore conversion capacities at the appropriate locations, while offshore options can help to overcome such issues.

This study considers a first multifunctional island as a demonstration case for possible further extension. To the extent that artificial islands may be considered in the further future, the above factors may all benefit the business case of offshore vs. onshore hydrogen generation: wind capacities and conversion capacities needed will probably get larger; projected wind farms will likely be located further from shore; more existing gas infrastructure may become available for hydrogen transport as the natural gas production will decline; and space limitations onshore and offshore as well as congestion issues of the onshore electric grid may grow in future.

7.2 Non-technical aspects and risk assessment

For the overall acceptance of artificial islands in the North Sea, it is important not only to start investment processes sufficiently in time, and to prepare licencing procedures well in advance, but most of all harness the support, commitment, and acceptance of various stakeholders.

Many stakeholders and many issues (legal, policy, ecological, energy, international, etc.) are at stake in case of the construction and exploitation of an artificial island in the complex environment of the North Sea. A good stakeholder process requires the preparation of an overarching and convincing vision and a plan that is shared with a wide group of stakeholders. This group includes as environmental protection organisations, wind park operators, gas and oil industry, fisheries, sea shipping, military as well as national government(s), the European Union, harbour authorities, onshore industry, network operators, and other energy system stakeholders. The realisation of such an island can only be successful if all stakeholders are taken seriously and their interests are considered. Ecology can be included by working together with environmental protection organisations and researchers. Building with nature is a key principle here. Legal, policy, and internationals aspects should be resolved together with governments. Energy functions are at the heart of the island concept and may help to solve system integration problems.

7.3 Results in context of other studies on energy islands

In this section we discuss the main similarities and differences in approach and outcomes from other studies on energy islands. We highlight studies executed by DNV GL (DNV GL, 2018), the North Sea Wind Power Hub consortium (North Sea Wind Power Hub, 2019b) and North Sea Energy programme (North Sea Energy, 2020c).

7.3.1 Scope of research and approach: Location specificity

What distinguishes this study from previous ones is the site-specific analysis for the multifunctional island. Even though the earlier DNV GL study (DNV GL, 2018) also focused on the IJmuiden Ver area, its analysis had a different focus and level of detail. The DNV GL study looks at the IJmuiden Ver area as a whole and takes into account various platform options and different pipeline options. The current study is more detailed and specific with respect to the location and the form of the offshore structure (a sandy island), the choice in export pipeline and electricity market modelling. The North Sea Energy programme (North Sea Energy, 2020c) does not specify any location, and the North Sea Wind Power Hub study (North Sea Wind Power Hub, 2019b) specifies four locations, and is therefore more general. Both of these latter studies have a more generic scope and focus on the main drivers important for the techno-economics of offshore hubs and islands, such as: wind capacity connected, distance to shore, water depth, type of island, and hydrogen conversion capacity.

As this study is applied to a specific location, i.e. just north of the IJmuiden Ver dedicated wind region, some 80 km from the Dutch coast, it takes into account the option of using specific existing offshore gas pipelines for the transport of hydrogen to shore, specifically the WGT, NGT and LOCAL trunk lines. The LOCAL trunk line is further considered in the detailed analysis. The reuse of existing infrastructure is also mentioned by the NSE and the NSWPH studies. The DNVGL study does a more in-depth analyses of pipeline options for the IJmuiden Ver area. This analysis is similar to the analysis done in this study and is based on the suitability of the pipelines, the capacity and a cost comparison between new and existing pipelines. However, what is not considered in the DNV GL study is the timing of abandonment. This is an important parameter since in the timing of the whole process. Furthermore, pipelines selected in this study are on the north side of the IJmuiden Ver area. We provide a detailed analysis of the LOCAL trunk. This choice is dictated by location of the island in the northern tip of the Ijmuiden Ver wind area.

The DNVGL study concludes that there is no significant advantage in using existing pipelines since they have to be replaced 5 to 23 years after construction of the island, since the pipelines do not have sufficient capacity, and since the existing pipeline length will be higher than of a new pipeline. These conclusions differ on some points from this study. The issue of capacity is not applicable for the pipelines selected in this study. All the pipelines that are selected have sufficient capacity to transport all hydrogen produced at peak wind capacity. This difference is caused by the 2 GW of wind assumed in this study versus the higher maximum wind capacity connected in the DNV GL study and by the selection of different pipeline sections (i.e. different diameters).

In terms of timing, this study explicitly focuses on an assumed extension of the build-up of offshore wind capacity north of the IJmuiden Ver offshore wind region and therefore faces somewhat less urgency in time than the IJmuiden Ver wind farm itself that is scheduled to be ready by 2027 and 2029 (IJmuiden Ver Alpha and Beta). This explains why a concern mentioned in a study by BLIX (BLIX Consultancy, 2018) — constructing an island would take too long given the current planning — does not apply for the case considered in this study.

7.3.2 Capacity of wind connected and share of hydrogen production

This study shows that the scale of the power-to-gas facility, and its location on an offshore island rather than onshore depends on a number of factors: the size and multifunctionality of the island itself; the distance of the island from shore; the degree to which existing gas infrastructure is available for the transport of hydrogen to shore; and the degree to which conversion and other activity offshore will benefit social acceptance as compared to a similar activity onshore. These factors are mentioned in other studies as well. Notably the results of (North Sea Energy, 2020c) and (North Sea Wind Power Hub, 2019b) suggest that the scale of the island and the energy conversion activity on it, is one of the crucial factors determining the feasibility of creating islands (with about 2 GW power-to-gas facility capacity being a critical scale).

The scale of the island and the amount of energy conversion determine the feasibility of an offshore island. North Sea Wind Power Hub shows that the optimal range of connected wind lies between 10 and 15 GW. Below 10 GW the benefits of scale are lost, above 15 GW technical limitations are introduced such as the necessity for additional collector platforms, resulting in additional costs (North Sea Wind Power Hub, 2019b). However, the levelized cost of energy (LCoE) is lower for a configuration where the 15 GW of wind is connected to multiple smaller islands versus one big island. In the North Sea Energy study (North Sea Energy, 2020c) wind capacities of 2, 5 and 20 GW being transmitted using an island are studied. The DNV GL study connects the total 4 GW of IJmuiden Ver to the island and also looks at scenarios where an additional 2 GW is installed (6 GW total). In this study 2 GW of additional wind capacity north of the Ijmuiden Ver area is connected to an island.

Each of the highlighted studies assumed a different ratio of power used to produce hydrogen. In the North Sea Energy study (North Sea Energy, 2020c) 70% or 30% is used. In the DNV GL (DNV GL, 2018) study power-to-hydrogen installations with various capacities from 100 MW to full capacity are considered. The North Sea Wind Power Hub looks at combinations of hydrogen and power as well as full hydrogen generation. All studies have a full electric benchmark. This is similar to this study, where we analyse the optimal ratio between hydrogen and electricity, with a full-electricity version as a benchmark.

The market modelling of the hybrid scenarios where the conversion is optimized were to the authors' knowledge not considered in the other studies. These scenarios do show the best economic results when compared with the other scenarios. This can be explained by the monetisation of electricity in case of high electricity prices and the monetisation of low electricity prices for hydrogen production (see Chapter 5 for the detailed analyses).

7.3.3 Techno-economic feasibility

Although the technological components for offshore hydrogen conversion are proven on shore, this is not yet the case at this scale and in offshore conditions. Recognising these technical challenges, existing studies yet agree that the technology is not the main problem, and that market conditions can be expected to be more important for the feasibility of offshore hydrogen generation. The challenge lies in the business case. This is also clear from the NPV that is calculated in the reviewed studies. The analyses show negative NPVs for the majority of the offshore scenarios. The scenarios in which the NPV values are positive were the cases calculated in this study, a case from the North Sea Energy study with a high hydrogen price (6 €/kg), and the cases in that study with a small amount (i.e. 30%) of hydrogen conversion, creating a larger revenue from electricity.
The results from existing studies, including this one, show that the business case is mainly controlled by the electricity and hydrogen price and CAPEX of electrolysers. The business case would therefore benefit from lower cost of capital, lower future power prices, lower CAPEX for electrolysers, increased electrolyser efficiency, increased green hydrogen prices and better inclusion of grid transport costs.

As offshore CAPEX is an important component in the cost breakdown for offshore hydrogen production, in this study and in North Sea Energy study (North Sea Energy, 2020c) an offshore cost factor (estimated at 1.5) is applied as a proxy for higher offshore installation costs in comparison to onshore installation of infrastructure components. Results from the North Sea Energy study indicate that break even between onshore and offshore production of hydrogen the offshore cost factor can be up to 1.5. This study shows the impact of this cost factor on the hydrogen production cost.

7.3.4 Multifunctionality energy islands

One of the conclusions of the North Sea Energy study (North Sea Energy, 2020c) is that the business case of the island can be improved by adding other use functions to the island. This is not confirmed by the North Sea Wind Power Hub study which states that additional use functions introduce planning risks through longer construction times and that additional benefits do not compensate for the additional operational expenses. The DNV GL study does not consider additional use functions. However, the economic analysis performed in this study shows opportunities for a multifunctional island as the cost per m^2 area is reduce if a larger island is considered. Developing an offshore island for multifunctional use is therefore recommended purely from an island construction point of view. Although no economic analysis has been performed, other use functions have been identified that could add value and support the business case for a multifunctional island.

7.3.5 Non-technical aspects and risks

All reviewed studies agree that one of the main non-technical and non-economic aspects that could create a barrier for an offshore island projects is the absence of a clear regulatory framework (North Sea Energy, 2020c) (North Sea Wind Power Hub, 2019b). Another important aspect mentioned by these studies, and in line with our findings, is the possible ecological impact of an artificial island. Knowledge on the impact of an artificial island on the environment is lacking. These possible impacts should be further investigated, in collaboration with relevant stakeholders.

7.4 Future improvements and outlook

There are a number of further research areas, both related to data and the methodology chosen, that came up during the research process and that should be explore further in order to improve the accuracy of the results.

7.4.1 Commodity price

The model outcomes show a high sensitivity with respect to the future commodity prices, in particular electricity and hydrogen prices. The price development paths of both energy carriers are unsure and affected by many factors, for instance, sustainable policy measures and technology development. Future electricity prices have been assessed by the PowerFlex model and are sensitive to the composition of future power generation capacities. Our 2050 price estimation is based on the assumption that all conventional power plants are converted to hydrogen-fired power plants, for which either a hydrogen price of 1.5 €/kg or 6 €/kg is used. The development of a transparent commodity market for hydrogen, with clear settlement prices, will also improve the accuracy of a future electricity prices predictions. The inclusion of (future) price interdependencies and variable hydrogen pricing will require further research. In addition, more insights are required in how future electricity price profiles might be altered by other flexibility resources (e.g. demand response). Differences in prices have a profound effect on the earning potential for offshore hydrogen generation.

7.4.2 Multi-cycle models

There are a number of limitations to the optimisation processes. First, flexibility revenues not (yet) included may work in favour of the P2G operator. Second, the optimisation in only run for the 2029 electricity price profile and results may differ if the optimisation period would be extended to 2050. Third, the optimisation model should be integrated with the other used models (e.g. PowerFlex, and MEFA) due to (potential) co-dependence between the future commodity prices. Further research should include a multi-cycle model which is able to integrate the co-dependence of both commodity prices. In other words, an coupled electricity and hydrogen market model is needed.

7.4.3 Large-scale offshore power-to-gas

No expertise is present (yet) in the field of operating GW-scale electrolysers, either on shore or offshore. The assumptions in this study are mainly based on cost projections of industrial cost data, resulting in relative high uncertainty in cost estimates. Therefore, further research and piloting expertise is required to validate both the 'offshore cost factor'[33] and the approach taken with regard to economics of scale. The expertise gained by the ISPT-led GW-scale electrolyser and the PosHYdon offshore P2G facility should therefore be followed with particular interest.

7.4.4 Onshoring location

This study does not contain a techno-economic comparison for various onshoring locations as presented in Section 3.2.4. Further research is required to determine whether Beverwijk and/or Den Helder (or even other locations) are the most optimal points for landing from techno-economic and spatial perspectives. In this study we assume that the system boundaries end at the onshoring location, which is connected to the (to be developed) hydrogen backbone connecting the region of Den Helder with Beverwijk, and further with other demand centres. A delay or absence of this hydrogen backbone is obviously an important

[33] A multiplication factor for offshore infrastructure used as a proxy for higher offshore installation cost in comparison to onshore installation of infrastructure components.

risk factor for the Den Helder landing point. It is less the case for other clusters with high hydrogen demand on site. Further research is required to evaluate the most suitable onshoring locations.

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A Land use on a 2 GW power-to-gas facility and a 2 GW HVDC facility

In the IJvertech study (IJvertech, 2019) the technical feasibility of offshore energy islands has been studied, including the required land for different functions to be included on the energy island. Two main functions are the transformation of AC coming from the wind turbines to DC which connect the island with the onshore grid (OTSO) and the transformation of AC from the wind turbine to gas to store power and be able to transport it to shore by pipelines. Both functions do not yet exist in offshore situation but after discussion with the grid operator TenneT as well as with several market players in these fields a list of separate facilities per function was made and an estimate of the required land per facility could be made. Both functions have been estimated as function of the electrical power which is incoming to the facility.

Please note that for OTSO also quay length and port basin area is defined, as for installation and maintenance larger components need to be brought into the facility as these are difficult to assemble and test on the island.

The information collected and reported in the IJvertech study (IJvertech, 2019) has also been used in this study to define land areas for the energy island.

Figure 50 - 2 GW Power to Gas Facility

		GW
P2G		2
		[ha]
4.1	Hydrogen plant	8.80
4.2	Operations building	0.04
4.3	Workshop P2G	0.15
4.4	Accomodation P2G	0.18
4.5	P2G roads + inefficiencies	1.83
	land/floating total [ha]	11.00
	port basin total [ha]	

Source: (IJvertech, 2019).

Figure 51 - Land use of a 2GW HVDC facility

		GW
OTSO		2
		[ha]
1.1	Land footprint Converters	7.70
1.2	Cable entry	0.14
1.3	Interconnections	0.08
1.4	Operations building	0.04
1.5	Workshop OTSO	0.10
1.6	Accomodation OTSO	0.13
1.7	OTSO roads + inefficiencies	1.64
1.8a	Basin OTSO	1.50
1.8a	Quay OTSO	0.75
	land/floating total [ha]	10.58
	port basin total [ha]	1.50

Source: (IJvertech, 2019).

B Extreme metocean conditions

Table 15 - Extreme metocean values for proposed island location. Data is taken from (DHI, 2019) with data from 1970-2018.

Variable	Extreme value (omni) — Return Period [Year]							
	1	2	5	10	50	100	1,000	10,000
Wind speed, 100mMSL, 10-min [m/s]	33.6	35.3	37.4	38.9	41.9	43.2	47.1	
Water level, Total, High [mLAT]	2.9	3.0	3.2	3.3	3.5	3.6	4.0	
Water level, Total, Low [mLAT]	-0.4	-0.5	-0.6	-0.7	-0.9	-0.9	-1.2	
Water level, Residual, High [m]	1.4	1.5	1.7	1.9	2.1	2.2	2.6	
Water level, Residual, Low [m]	-0.9	-1.0	-1.1	-1.2	-1.4	-1.4	-1.7	
Current Speed, Total, Depth-Averaged [m/s]	0.9	1.0	1.0	1.0	1.1	1.1	1.2	
Current Speed, Residual, Depth-Averaged [m/s]	0.6	0.7	0.7	0.8	0.9	1.0	1.2	
Significant wave height, 3hr, Hm0 [m]	5.6	6.0	6.5	6.9	7.6	7.8	8.8	9.6
Peak wave period, Tp, ass. with Hm0,3h [s]	10.4	10.9	11.5	11.9	12.8	13.0	14.1	14.9
Maximum wave height, Hmax [m]	10.5	11.2	12.1	12.8	14.3	14.8	16.8	18.6
Wave period, T, ass. with Hmax [s]	8.9	9.6	9.9	10.0	10.8	10.8	11.9	11.7
Maximum crest level, Cmax, SWL [mSWL]	6.6	7.1	7.8	8.3	9.4	9.7	11.3	12.7
Maximum crest level, Cmax, MSL [mMSL]	7.7	8.3	9.0	9.6	10.8	11.3	13.0	14.5
Maximum crest level, Cmax, LAT [mLAT]	8.8	9.4	10.1	10.6	11.9	12.4	14.0	15.5

C Additional use functions

These additional use functions are based on the North Sea Energy 3 programme (North Sea Region, 2020).

Methods

During the programme, a scoring workshop was organized with five experts from Royal HaskoningDHV and TNO from relevant domains. The use functions were scored by following a PESTTEL analysis (Political, Economic, Social, Technological, Timing and organizational, Environmental and Legislative), where the scores were defined as follows: very positive (++), positive (+), neutral (0), negative (-) and very negative (--). A positive result of ++ or + for all of the PESTTEL factors of one use function would serve as an indication of a high-potential use function. Whereas, when a score of -- was given for at least one of the PESTTEL factors, we assigned the respective use function to a red flag category even if the other factors score high. To assess the scoring, we looked both at the average score of a function (indicating overall performance) and the lowest score (indicating red-flag conditions). The scores were translated to numerical values 0-5 for further analysis.
To summarize, we assign the use functions to three categories as follows: high-potentials (average > 3.5, no red flags), uncertainties (2.5 < average < = 3.5, no red flags) and red-flags (average < =2.5, any use functions with a red flag score for one or more of the PESTTEL factors).

Assumptions

We score a total of 26 additional use functions that were identified in an earlier workshop with Royal HaskoningDHV. There, it was also determined what size (in GW) an offshore energy island has to be to accommodate a certain use functions. If applicable, a comparison between the offshore and onshore alternative was made to assess the value of a use function.

Table 16 - List of 26 additional use functions that were qualitatively scored in NSE 3 work package 3.6 (North Sea Region, 2020)

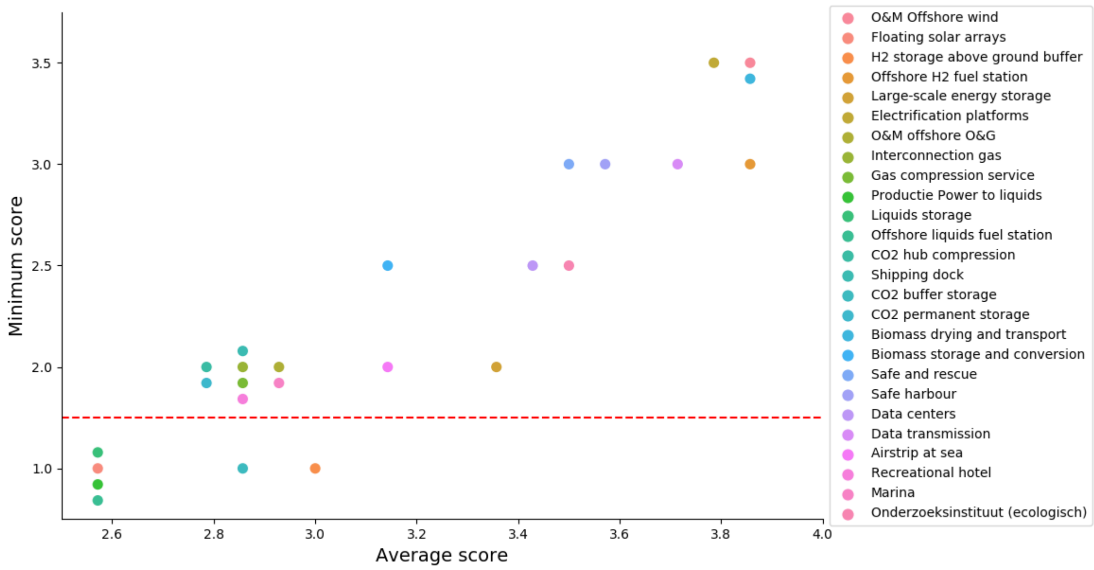
Category	Use function
Electrons	O&M offshore wind
Electrons	Floating solar arrays
Electrons	Interconnection
Hydrogen	Hydrogen storage aboveground buffer
Hydrogen	Offshore hydrogen fuel station
Hydrogen	Large-scale energy storage
Oil and gas	Electrification platforms
Oil and gas	O&M offshore O&G
Oil and gas	Interconnection gas
Oil and gas	Gas compression service
Liquids	Production power to liquids
Liquids	Liquid storage
Liquids	Offshore liquids fuel station

Category	Use function
CCS	CO2 hub compression
CCS	Shipping dock
CCS	CO2 buffer storage
CCS	CO2 permanent storage
Macro algae	Biomass drying and transport
Macro algae	Biomass storage and conversion
Ancillary services	Safe and rescue
Ancillary services	Safe harbor
Ancillary services	Data centers
Ancillary services	Data transmission
Ancillary services	Airstrip at sea
Ancillary services	Recreational hotel
Ancillary services	Marina
Ancillary services	Ecological research institute

Results

Figure 52 shows an overview of the resulting scoring, with the average score (x-axis) and minimum score (y-axis) per use functions. The scoring resulted in seven high potentials, fourteen uncertainties and six red flags.

Figure 52 - PESTTEL scoring results for 26 additional functions with average (x-axis) and minimum (y-axis) score. Red line indicates threshold below which functions contain a red-flag characteristic



Source: (North Sea Region, 2020).

D Hydrogen storage options

The option to store hydrogen in large volumes and at relative attractive economics makes it an attractive energy carrier. Hydrogen storage could be warranted on the island to reach optimal process conditions (i.e. temporary buffering) or for strategic economic reasons to deliver energy system services. It is outside the scope of the project to assess the detailed techno-economic opportunities and challenges of hydrogen storage on- and offshore. Instead, a brief overview of potential relevant storage options is provided below with some key characteristics.

Hydrogen can be stored in tanks and undergrounds. There are several relevant types of storage, each type will be briefly described (see below):
1. Storage of gaseous hydrogen in tanks.
2. Line packing (storage in pipelines).
3. Liquid hydrogen storage.
4. Storage in salt caverns.
5. Depleted gas fields.
6. Aquifers.

Storage of gaseous hydrogen in tanks

In gaseous form and at atmospheric conditions hydrogen has an energy density per unit volume of 12.8 MJ/Nm^3 (HHV). This is three times lower than of natural gas (39.8 MJ/Nm$^{3)}$. However, storage of hydrogen as a compressed gas in a tank is currently the most mature form of storage. The average storage capacity of a hydrogen tank for a fuel cell vehicle is 5 kg (about 56 Nm^3). It is widely used to transport hydrogen, and is the preferred technology for onboard automotive storage.

Liquid hydrogen storage

Liquid hydrogen has a volumetric energy density of 8,519 MJ/m^3 (LHV basis, at 1 atm and –253°C). This is more than 600 times higher when compared to the same volume of gaseous hydrogen at atmospheric conditions and ambient temperature. The technique is already applied at the Kennedy Space Center where liquid hydrogen is stored in above ground spherical tanks (Figure 53 - Liquid Hydrogen storage tanks, Kennedy Space Center USA (Granath, 2017)Figure 53). The tank has a volume of 3,200 m^3 (850,000 gallons; Granath, 2019). This equals about 2.5 million Nm^3 of hydrogen in gaseous form.

Figure 53 - Liquid Hydrogen storage tanks, Kennedy Space Center USA (Granath, 2017)

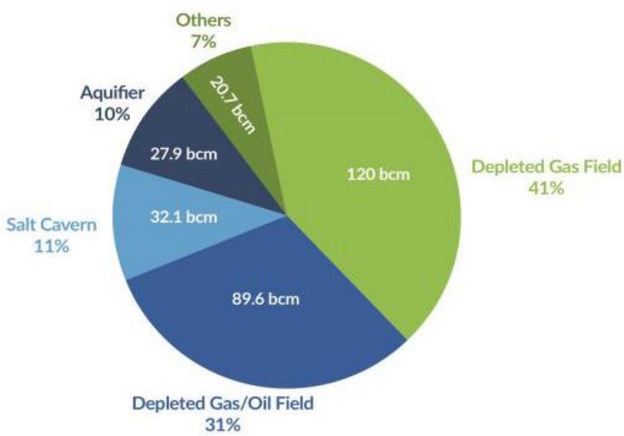
Line packing

Line packing uses the volume of gas available within the pipeline system itself.
By increasing the pressure within the pipeline system, the volume of gas that is stored in it increases and vice versa. The technique is used by transmission system operators to balance supply and demand on an hourly basis (intraday). By modifying the pipelines to the transport of hydrogen, this technique could be applied for short term hydrogen storage. The capacity of this technique depends on the size and length of the available pipelines as well as the operating pressures (and the limits).

Underground storage of hydrogen

Underground storage is already widely used for storing a variety of gases. In particular, underground storage of natural gas is widespread. Underground storage is used to provide flexibility in matching demand and supply in the gas infrastructure and markets. In total, about 300 billion Nm^3 of natural gas is stored underground worldwide (Figure 54)) the majority of which in depleted fields, salt caverns, and aquifers.

Figure 54 - Global Gas Storage Capacity (billion Nm^3 working volume)



Source: (IGU, 2016).

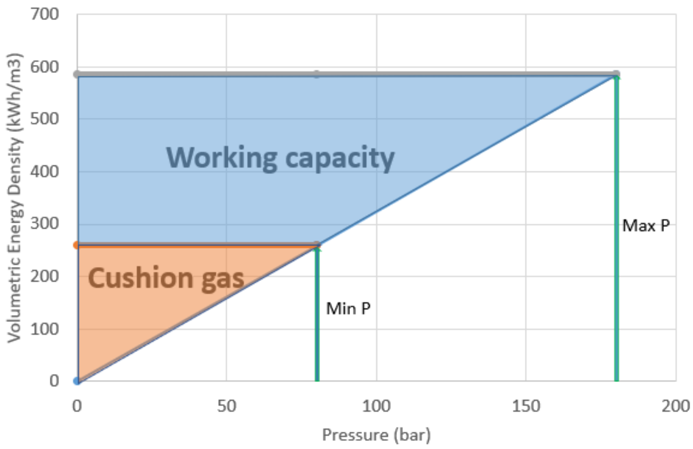
Because underground storage of hydrogen is in many ways similar to storing natural gas, the three most widely used underground storage technologies for natural gas (storage in salt caverns, depleted gas fields, and aquifers), will be described in more detail in the next three sections in the context of their suitability for storing hydrogen.

Salt cavern storage

Salt cavern storage is a widely used technology for storing a variety of gases (natural gas, ethane, ethylene, hydrogen, helium, air, nitrogen) and liquids (oil and fuels). The fact that rock salt is impermeable makes a salt cavern a very suitable storage container for fluids or gases. In practice, caverns that are solution-mined for the purpose of gas storage rarely exceed 1,000,000 m^3.

The storage capacity of a given cavern is a function of its volume and the operating pressure range. An example is given below in Figure 55, showing the estimated storage capacity of a salt cavern in the Groningen area (in the Netherlands), based on data provided by Gasunie for the H-vision project. The total capacity of about 300 kWh/m^3 is equivalent to storing 100 Nm^3 of hydrogen for every m^3 of geometric volume inside the cavern.

Figure 55 - Indication of salt cavern capacity as a function of pressure (data from Gasunie, H-vision project)



Gas processing facilities at the surface includes compression, expansion, purification, and drying. Purification is an important step to ensure that the quality of the hydrogen meets the requirements, which are very strict for use as chemical feedstock or in fuel cells (electricity generation, mobility).

Depleted gas fields

A depleted field can be considered an effective storage medium for hydrocarbons and possibly also for hydrogen. The design for hydrogen storage in a depleted field is similar to that of a cavern storage, which in this case is a depleted hydrocarbon reservoir, and wells connecting the reservoir to above-ground facilities for compression, purification and drying. One of the differences compared to storage in caverns is the possible contamination of the gas after being stored in the reservoir, which makes more extensive gas treatment necessary.

The amount of hydrogen that can be stored in a depleted gas field typically lies between 0.5 and 5 billion Nm^3 (Gessel, et al., 2018). It is highly dependent on the size of the field (as measured by the volume of natural gas that was initially in place before production started), the required injectivity (rate at which the hydrogen is injected into the field) and the required productivity (rate at which hydrogen is withdrawn from storage).

There are currently no commercial projects in the world where pure hydrogen is stored in a depleted gas field. However, in recent years, several demonstration projects have been executed. In these projects hydrogen was mixed with natural gas and stored in depleted fields, one in Argentina (Hychico project; (Pérez, et al., 2017)) and one in Austria (Sun Storage project). Overall this technique has a very low TRL level, and is accompanied by a number of technical challenges that need to be overcome.

Aquifers

Aquifer storage is very similar to storage of gas in a depleted gas reservoir. In both cases, the gas is stored in porous and permeable (reservoir) rock formations, typically sandstones or carbonate rocks, hence they are also collectively referred to as “pore storages”. In order to be suitable for gas storage, the aquifer needs to be a gas-tight and overlain by an impermeable cap rock.
According to the Gas Infrastructure Europe database (GIE, 2018) aquifer storage facilities for natural gas are operated at 25 different locations within Europe. The total working gas capacity of all locations is approximately 19 billion Nm^3, which is in a similar order of magnitude as for natural gas storage in salt caverns in Europe (HyUnder, 2013).

Applicability to the IJvergas Island

The type of storage that is the most suitable on or near the island depends on the capacity needed (GW loading and production), the energy volume (amount of GWh storage to support short term and/or long-term seasonal storage), the TRL-level of the available techniques, the footprint of the facilities and the economics. The type of storage that would be necessary for the hydrogen produced on the island is controlled by the hydrogen demand and by peaks in the wind power that is brought to the island. The necessity of long/short term storage can be inferred from the techno-economic analysis that will be executed in the following WPs.

Figure x shows the known offshore salt formations, that are at sufficient depth to be able to use for storage. Also shown are the offshore hydrocarbon reservoirs. A recent study by EBN and TNO has indicated that the offshore hydrocarbon reservoirs could offer 60 billion m^3 of working volume equaling 179 TWh of hydrogen. The challenge is screening and assessing the individual suitability for storing hydrogen offshore.

With respect to short-term or smaller scale storage, liquid storage and line packing could both prove to be suitable. The capacity of line packing is relative small but almost inherent part of pipeline transport operations, whereas liquid storage will require additional infrastructure and more complex process of compression and storage in tanks which require most likely higher investment costs.

Next to the storage needs and the type of storage that would fit the need also an evaluation is needed whether storage offshore is more attractive than onshore storage. Within such an assessment the technical, market and societal factors should be taken into account. This is not included in the current scope, but is recommended to pursue in future R&D work.

Table 17 - Characteristics of hydrogen storage options

Storage type	Relevant storage period	Volume	TRL
Gaseous storage	-	5kg (56 Nm^3)	Mature
Liquid storage	hours to weeks	2.5 million Nm^3	Mature
Line packing	hours to day	-	Mature
Offshore salt caverns	Hours to seasonal	100 Nm^3/m^3	Mature, but not applied offshore
Hydrocarbon reservoir	hours to seasonal	0.5 and 5 billion Nm^3	Immature, R&D projects exist
Aquifer	hours to seasonal	100 Nm^3/m^3	Immature

E PowerFlex simulations

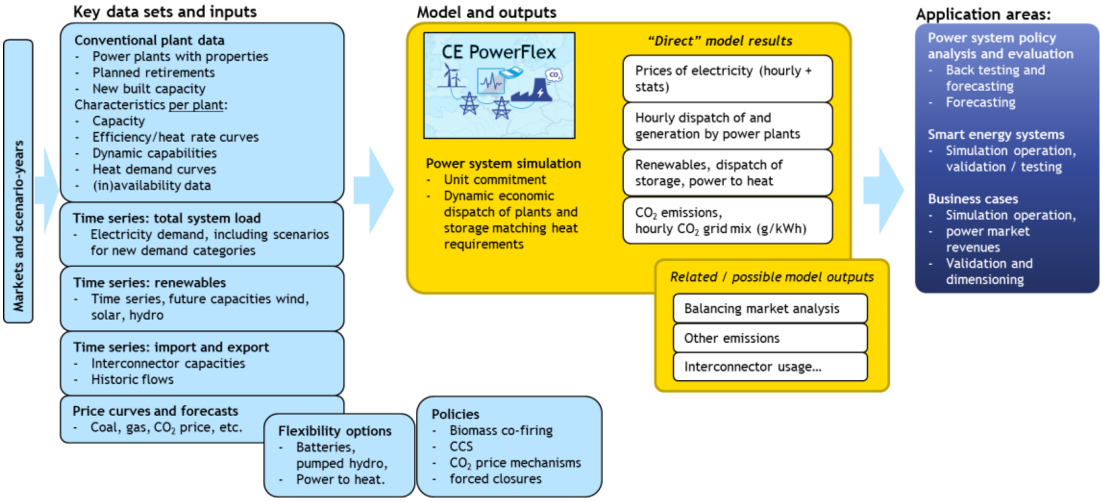
This appendix discusses the PowerFlex simulations used in the economic evaluation of the multifunctional island scenarios. We start our discussion with a description of the PowerFlex model, next we discuss the reference scenario for both the 2029 and 2050 time frames, followed by a discussion of how the four IJvergas scenarios are simulated. We conclude with the results of the power price simulations of the four IJvergas scenarios.

E.1 The PowerFlex model

PowerFlex simulates the dynamic operation of the electricity system via the price driven dispatch of power plants, storage units and power-to-heat installations. The assets are dispatched to achieve lowest overall system costs, reflecting relevant constraints.
The model includes per generating unit: quadratic efficiency curves, must run, CHP, heat demand time curves, minimum up/down times and start costs, and for balancing/short-term dispatch: ramping capabilities.

The heart of the model is the solver. The solver employs the technique dynamic economic dispatch using Lagrangian relaxation. This algorithm is well documented in literature. Simulations are carried out for the Netherlands and Germany as model core regions. Effects of neighbouring countries not in the model core region are incorporated with their hourly interconnection time series that may be derived from other models, or from the ENTSO-E transparency data.

Figure 56 - Data sets, inputs, model characteristics, outputs and model application areas



E.2 Assumed reference situation

We study the effects of the power-to-gas facility coupled to a 2 GW wind park on the electricity market price with respect to a reference situation without the power-to-gas facility and the wind farm. We model the reference in two moments in time: in 2029 and 2050. Each of them is detailed below.

2029 reference: Climate Agreement

The 2029 Climate Agreement scenario is based on the calculations of the intended policies[34] from the Climate Agreement by the Netherlands Environmental Agency. In this scenario, some coal-fired power plants are still active. We deliberately choose to simulate 2029 since this year represents a clear turning point in de Dutch power system and energy markets. The installed capacity of power plants and renewable energy production is given in Table 18.

Table 18 - Installed capacity for electricity production in 2029 reference scenario (GW)

	Netherlands	Germany
Coal	3	10
Lignite	0	8
Natural gas	15	41
Biomass & Waste	1.5	9
Others[35]	1.5	1
Total conventional capacity	**21**	**70**
Solar PV	19	91
Onshore wind	9	82
Off-shore wind	12	17
Hydro	0	6
Total renewable capacity	**40**	**195**

The German power market is included in the PowerFlex model. Therefore, transfer of electricity between the Netherlands and Germany is included in the model calculations. Interconnections with other countries[36] are not explicitly included in de model calculations. Instead the electricity transfer with these countries is included in the input[37]. It is assumed that cross-border electricity flows with these countries remain constant (ENTSO-E, 2017).

2050 reference: International hydrogen scenario

For 2050 a so-called international hydrogen scenario from the Grid of the Future (CE Delft, 2017) is used. This scenario builds on the 2029 Climate Agreement scenario. It assumes that no additional electrification occurs after 2029[38] and that the electricity demand and installed capacity of renewable energy sources connected to the grid remain the same as in

[34] In Dutch: 'vastgesteld en voorgenomen beleid'.

[35] BFG (Boiler Feed Gas), nuclear, oil and geothermal.

[36] The Dutch electricity grid is connected to the grid of the UK, Belgium, Denmark and Norway. The German grid is connected to Luxemburg, France, Switzerland, Austria, the Czech Republic, Poland, Denmark and Sweden.

[37] The cross-border transfer is added to the electricity demand.

[38] This scenario assumes that the remaining energy demand will be covered by other energy sources, like imported hydrogen.

2029. Any additional renewable generation capacity installed after 2029 is assumed to be used to produce green hydrogen. All conventional power plants are converted to hydrogen-fired power plants. CHP's[39] are replaced by hydrogen fuel cells. Closed conventional power plants, like coal-fired power plants, are replaced by high efficiency hydrogen power plants. Hydrogen is assumed to be partly produced in the Netherlands but is assumed to be mainly imported. The installed capacity of power plants and renewable energy production is given in Table 19.

Table 19 - Installed capacity electricity production 2050 reference scenario (GW).

	Netherlands	Germany
Hydrogen	22	67
CCGT[40]	17	67
Fuel cell	5	0
Biomass &Waste	1.5	9
Others	1	1
Total conventional capacity	**24**	**76**
Solar PV	19	91
Onshore wind	9	82
Off-shore wind	12	17
Hydro	0	6
Total renewable capacity	**40**	**195**

The same cross border electricity transfer as 2029 is included in this scenario.

E.3 Power price simulations of the four scenarios

For the four scenarios in this study, only scenarios with a cable connection between the power-to-gas facility and the onshore grid are relevant. Since in Scenario 2 all electricity is used for production of hydrogen offshore, from the electricity market perspective it reduces to the reference (see above). Therefore, this scenario is not discussed in this paragraph. For all other scenarios, 2029 and 2050 cases are simulated.

For approximately 2000 hours per year, the renewable production exceeds the demand. These hours include production surpluses from the Netherlands and from Germany. This surplus of renewable generation is cheap and can thus be used by the power-to-gas facility. In times of electricity surplus, the PowerFlex model yields negative prices. However, we expect that these negative prices will not occur in reality as demand will adapt to generation and/or generation will be curtailed.

When the renewable production is lower than the demand, additional production from power plants will be needed to cover any additional demand. This means that the prices of the day-ahead market would apply which are set by the marginal costs of power plants. We expect these prices to be relatively high.

In general, we expect that the electricity produced from renewable sources (solar PV and wind) will primarily be sold using bilateral contracts. We foresee that the price negotiated

[39] Combined heat and power.

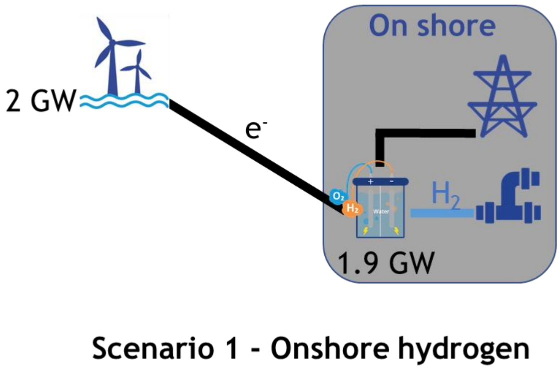
[40] Combined Cycle Gas Turbine.

in such contracts will be equal to the production cost plus an additional profit margin. For the operation of the power-to-gas facility this means that the operator can be assumed to have a bilateral contract with the wind park operator (see also Section 4.2.2. In times of generation surplus, the electrolyser operator can buy additional electricity from the market at low cost (provided that the cable capacity allows for additional transport of electricity). In times of demand surplus prices will be higher than the bilateral contract prices.

E.3.1 Scenario 1 – Onshore hydrogen

In this scenario, the power-to-gas facility is built on shore. The wind farm is only connected to the electrolyser, not to the national electricity grid. The capacity of both the electrolyser and the connecting power cable is 1.9 GW. This assumes a net capacity of 95% for the 2 GW-wind farm. This factor takes into account losses from wake effect and collection system. The power-to-gas facility is connected to the national electricity grid. When generation is below 1.9 GW, the electrolyser can thus use additional electricity from the grid. The configuration is shown in Figure 57.

Figure 57 – Configuration of Scenario 1 – onshore hydrogen



Since the wind farm has no connection to the onshore electricity grid, all electricity produced by the wind farm is either consumed by the power-to-gas facility, or curtailed. The owner of the power-to-gas facility can choose to buy electricity from the grid when its capacity is not entirely covered by the production of the wind farm. Finally, the owner of the power-to-gas facility can choose to buy electricity from the grid instead of using electricity produced by the wind farm. However, in this case the owner of the power-to-gas facility still has to pay for the electricity produced by the wind farm, since the wind farm cannot sell its electricity to another party[41]. Each of these three cases are simulated with PowerFlex. An overview of the cases is given in the following table.

[41] This is a rational choice only if market prices are negative.

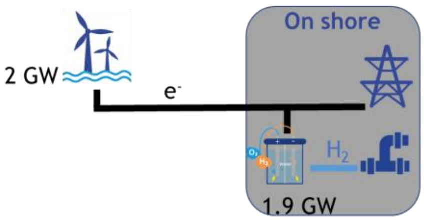
Table 1 - Overview simulated cases of Scenario 1 in PowerFlex

Case	Description	Consequences for PowerFlex simulation	Relevant electricity price for power-to-gas facility
1	Power-to-gas facility uses electricity produced by wind farm. No additional electricity is bought from grid	Case equals reference scenario	Price of wind power production
2	Power-to-gas facility uses electricity produced by the wind farm. Additional electricity is bought from grid to cover full capacity	Reference scenario is extended with an additional electricity demand of 1.9 GW minus production of the wind farm	– Price of wind power production (for share used from wind farm) – Simulated market electricity price (for share bought from the grid)
3	All electricity is bought from the grid. Electricity produced by wind farm is curtailed	Reference scenario is extended with an additional electricity demand of 1.9 GW	– Price wind power production (for curtailed production wind farm) – Simulated market electricity price (for electricity bought from the grid)

E.3.2 Scenario 3 – Onshore hybrid

In Scenario 3, both the wind farm and the power-to-gas facility are connected to the national grid and to each other. Therefore, market electricity prices are applicable in all situations. For two extreme cases the market electricity price is simulated, one with no demand from the power-to-gas facility and one with full demand. All other cases can be interpolated between these two extremes. The options are given in Table 20.

Figure 58 - Configuration Scenario 3



Scenario 3 - Onshore hybrid

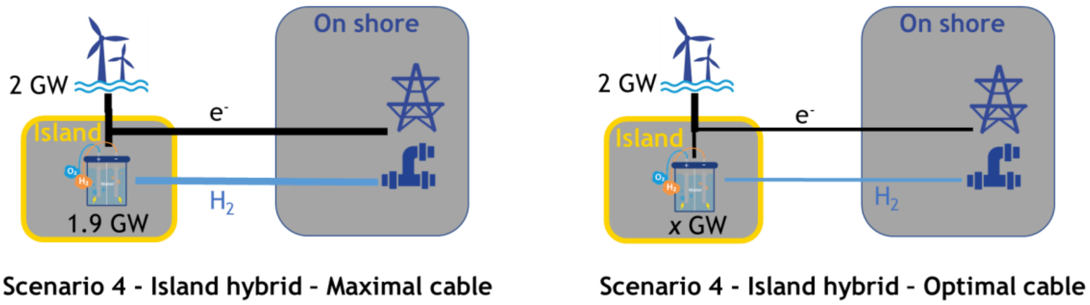
Table 20 - Overview simulated cases of Scenario 3 in PowerFlex

Case	Description	Consequences for PowerFlex simulation	Relevant electricity price for power-to-gas facility
1	No electricity bought from grid or wind farm, i.e. the power-to-gas facility is not running	Reference scenario is extended with: – 2 GW additional installed capacity off-shore wind (max. 1.9 GW production) – No additional electricity demand	Simulated market electricity price/bilateral agreement
2	Full capacity covered by electricity bought from grid or wind farm, i.e. the power-to-gas facility operates at full capacity	Reference scenario is extended with: – 2 GW additional installed capacity off-shore wind (max 1.9 GW production) – 1.9 GW additional electricity demand	Simulated market electricity price

E.3.3 Scenario 4 - Island hybrid

Scenario 4 is the island hybrid scenario. In this scenario, the power-to-gas facility is located on an island and the wind farm is connected to both the power-to-gas facility and the national electricity grid. This scenario consists of two subcases: maximal cable and optimal cable. In the maximal cable scenario, the capacity of the power-to-gas facility and the power cable are 1.9 GW each. This assumes a capacity factor of 95% compared to the 2 GW capacity of the wind farm for both the national grid connection and the power-to-gas facility connection. In the optimal cable scenario, the capacity of the power-to-gas facility and the power cables are optimised. The configurations are shown in Figure 59.

Figure 59 - Configuration Scenario 4-Full and Scenario 4-Small



Scenario 4 - maximal cable is identical to Scenario 3 with one exception: the power-to-gas facility is placed on an island instead of onshore. However, the location of the power-to-gas facility does not affect the input (and consequentially the output) of the PowerFlex simulation. Therefore, the results of Scenario 4 - maximal cable are identical to the results of Scenario 3.

To model scenario – optimal cable, three extreme cases are considered. The first case is the absence of the hydrogen production facility. This case is trivial and therefore not modelled in PowerFlex. The two other cases are the maximal capacity of 1.9 GW, and a half-capacity of 0.95 GW. All other cases can be interpolated between these two extremes. The options are given in Table 21.

Table 21 - Overview simulated cases of *Scenario 4-Small* in PowerFlex

Case	Description	Consequences for PowerFlex simulation	Relevant electricity price for power-to-gas facility
1	Only mandatory electricity bought from wind farm by power-to-gas facility (production above 1 GW). No additional electricity is bought from the national grid	Reference scenario is extended with: – 2 GW additional installed capacity off-shore wind capped to 0.95 GW (max. 0.95 GW production will be provided to the grid) – No additional electricity demand	Simulated market electricity price
2	Additional electricity is bought to satisfy the full capacity of the power-to-gas facility	Reference scenario is extended with: – 2 GW additional installed capacity off-shore wind capped to 0.95 GW (max. 0.95 GW production will be provided to the grid) – Additional electricity demand of 0.95 GW minus the wind electricity produced above 0.95 GW	Simulated market electricity price

E.4 Results and implications

For different scenarios, the electricity market prices are simulated for extreme cases: when the owner of the power-to-gas facility decides to buy no additional electricity from the grid and when the owner of the power-to-gas facility decides to buy the maximal possible quantity of electricity from the grid (until the full capacity of the power-to-gas facility is covered). The electricity market prices increase when the owner of the power-to-gas facility decides to buy electricity from the grid, since the electricity demand increases and additional power plants have to be turned on. When the owner of the power-to-gas facility decides to buy some electricity from the grid, but less than the maximal possible quantity, the electricity price will be in between the two extremes (no additional electricity bought and maximum possible quantity bought). It is assumed that the change of the electricity price is proportional to the demand of the power-to-gas facility in this interval[42]:

$$Price = Price_{min} + f * (Price_{max} - Price_{min}).$$

In this formula $Price$ is the price that the has to be paid by the owner of the power-to-gas facility, f is the fraction of the maximum amount of electricity bought, $Price_{max}$ is the electricity price if the maximum amount of electricity is bought and $Price_{min}$ is the electricity price if no additional electricity is bought.

The prices $Price_{max}$ and $Price_{min}$ of each of the simulations are given in the following paragraphs.

42 This means that if the owner of the electrolyser decides to buy half of the possible amount of electricity he could consume in the given situation, the electricity price will be in the middle between the two extremes.

E.4.1 Simulation results for 2029

In the 2029 runs, the average electricity price in the reference is 58 €/MWh. The average prices and the price duration curves of all simulated cases for the respective scenarios are given below.

Table 22 - Reference/Scenario 2

Case	Description	Average electricity price (€/MWh)
1	Electrolyser uses electricity produced by wind farm. No additional electricity bought from grid.	58

For each scenario intermediate situations should be interpolated between the min. and max. cases, depending on the additional electricity bought from the onshore grid.

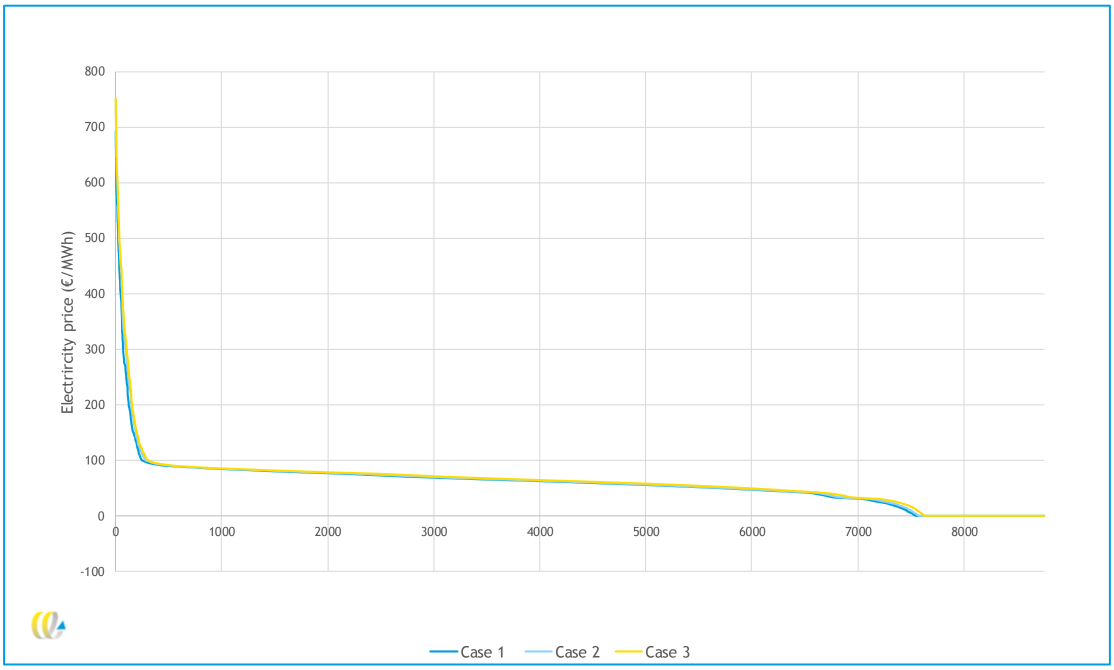
Scenario 1

Table 23 - Results of simulations for scenario 1 for 2029

Case	Description	Average electricity price (€/MWh)
1 (min)	Electrolyser uses electricity produced by wind farm. No additional electricity bought from grid. Equal to reference scenario.	58
2 (mid)	Electrolyser uses electricity produced by wind farm. Additional electricity bought from grid to cover full capacity.	59
3 (max)	All electricity is bought from the grid. Electricity produced by wind farm is curtailed.	62

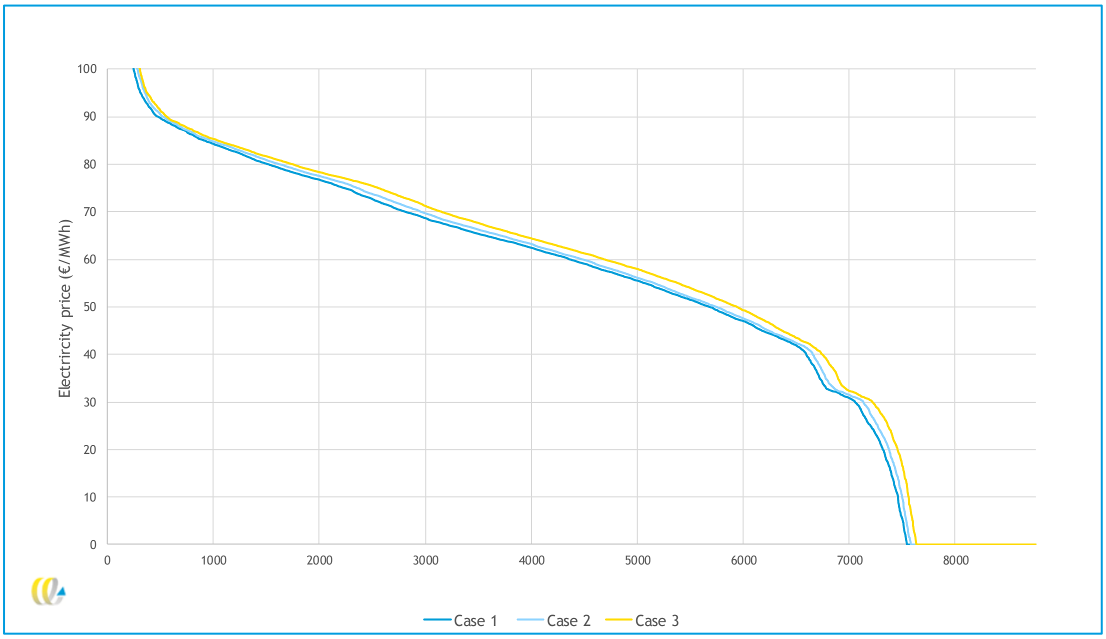
Note that in this scenario, Case 2 is a special case in which first all electricity from the wind farm is used and the full remaining capacity is bought from the grid.

Figure 60 - Price duration curves for Scenario 1 for 2029



It can be seen that the difference between the prices for the three cases is very small. However, there is some difference as can be seen in the zoomed in price duration curve in the following figure. The same applies to the other scenarios.

Figure 61 - Price duration curves for Scenario 1 for 2029 zoomed in

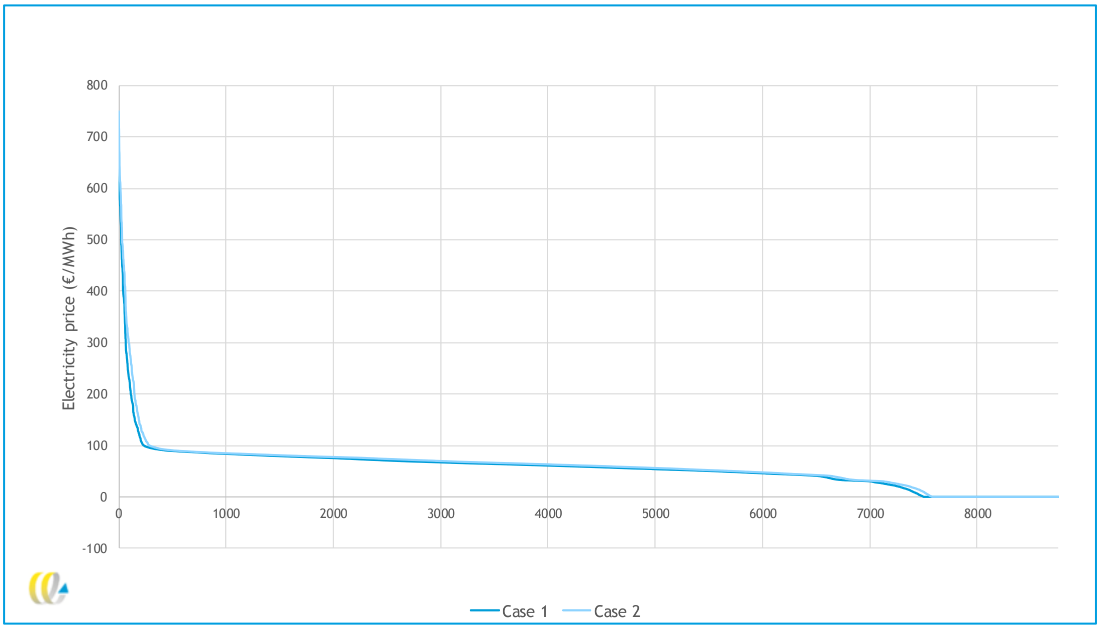


Scenario 3 and Scenario 4 - Maximal cable

Table 24 - Results of simulations for Scenario 3 and 4 - maximal cable for 2029

Case	Description	Average electricity price (€/MWh)
1 (min)	No electricity bought from grid/wind farm, i.e. power-to-gas facility is not running	57
2 (max)	Full capacity covered by electricity bought from grid/wind farm, i.e. power-to-gas facility operates at full capacity	58

Figure 62 - Price duration curves for Scenario 3 and 4 - maximal cable for 2029

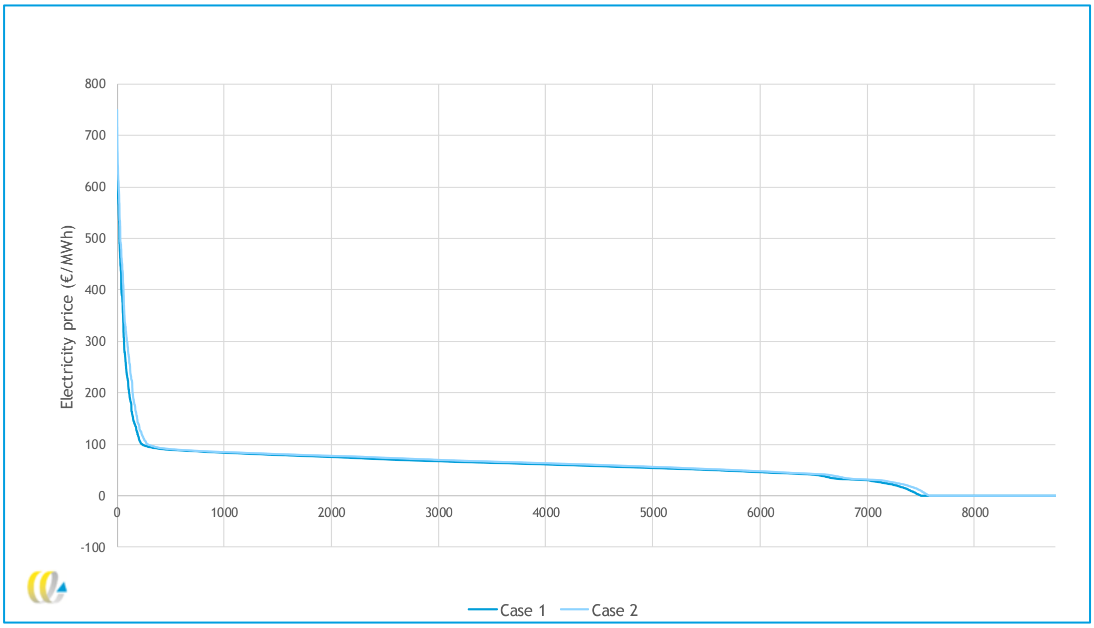


Scenario 4 - half capacity

Table 25 - Results of simulations for Scenario 4 - half capacity for 2029

Case	Description	Average electricity price (€/MWh)
1 (min)	Only mandatory electricity bought from wind farm by power-to-gas facility (production above 1 GW). No additional electricity is bought from the national grid.	57
2 (max)	Additional electricity is bought to cover the full capacity of the power-to-gas facility.	60

Figure 63 - Price duration curves for Scenario 4 - half capacity for 2029



E.4.2 Simulation results for 2050

In the 2050 runs, the average electricity price in the reference scenario is 117 €/MWh. The average prices and the price duration curves of all simulated situations for the respective scenarios are given below. Similarly to the 2029 runs, it is assumed that the renewable production is sold with bilateral contracts with a price equal to the cost price plus an additional profit margin.

Table 26 - Reference/Scenario 2

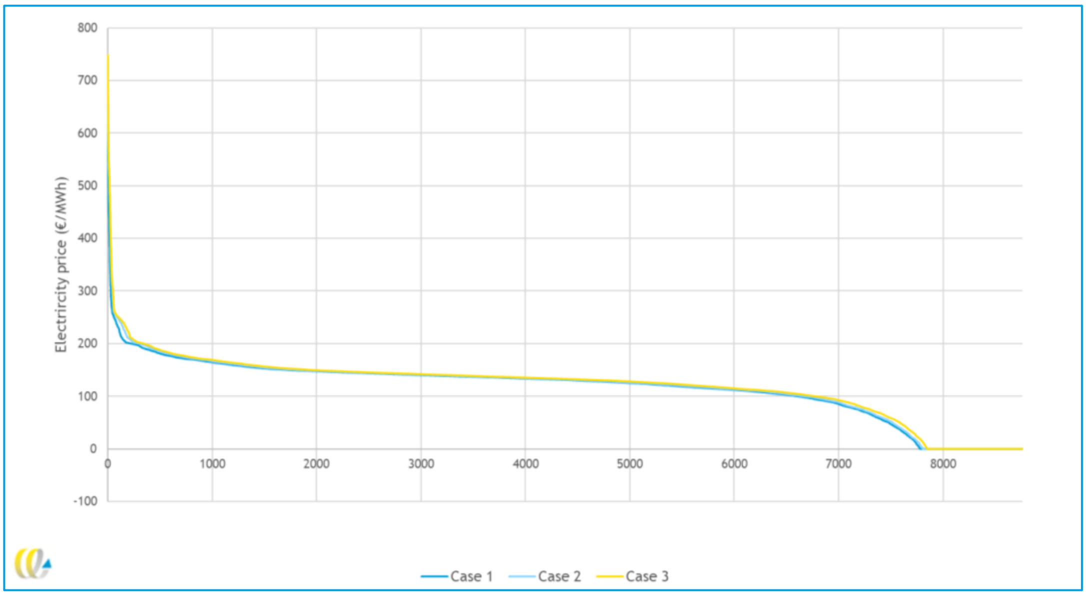
Case	Description	Average electricity price (€/MWh)
1	Electrolyser uses electricity produced by wind farm. No additional electricity bought from grid.	117

Scenario 1

Table 27 - Results of simulations for Scenario 1 for 2050

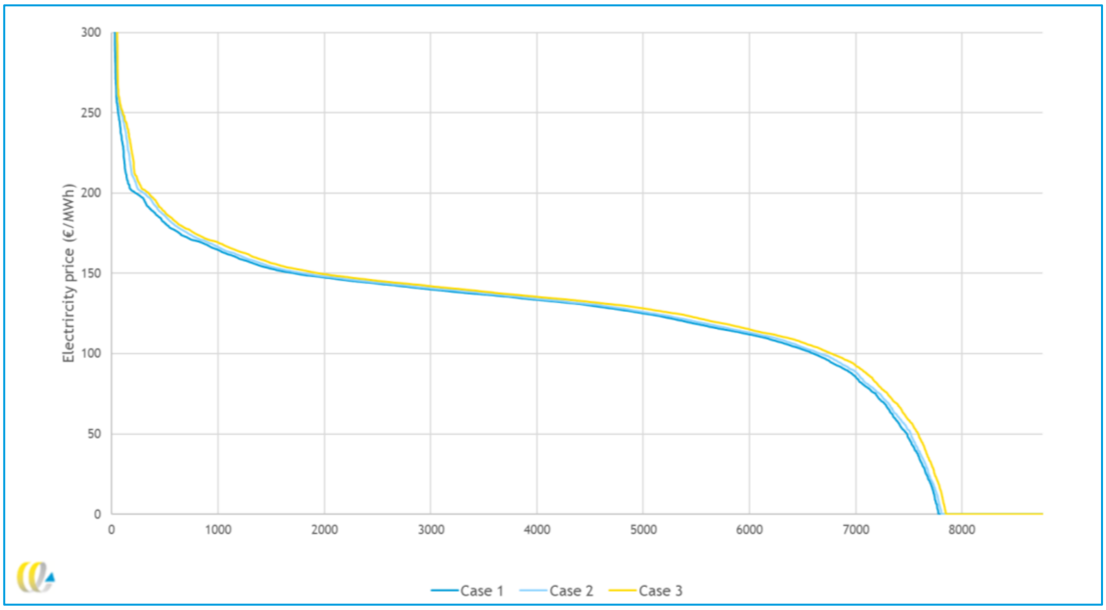
Case	Description	Average electricity price (€/MWh)
1 (min)	Electrolyser uses electricity produced by wind farm. No additional electricity bought from grid. Equal to reference scenario.	117
2 (mid)	Electrolyser uses electricity produced by wind farm. Additional electricity bought from grid to cover full capacity.	119
3 (max)	All electricity is bought from the grid. Electricity produced by wind farm is curtailed.	121

Figure 64 - Price duration curves for Scenario 1 for 2050



It can be seen that the price differences between the three cases are small in 2050 as well, but some difference occur as can be seen in the next figure.

Figure 65 - Price duration curves for Scenario 1 for 2050, zoomed in

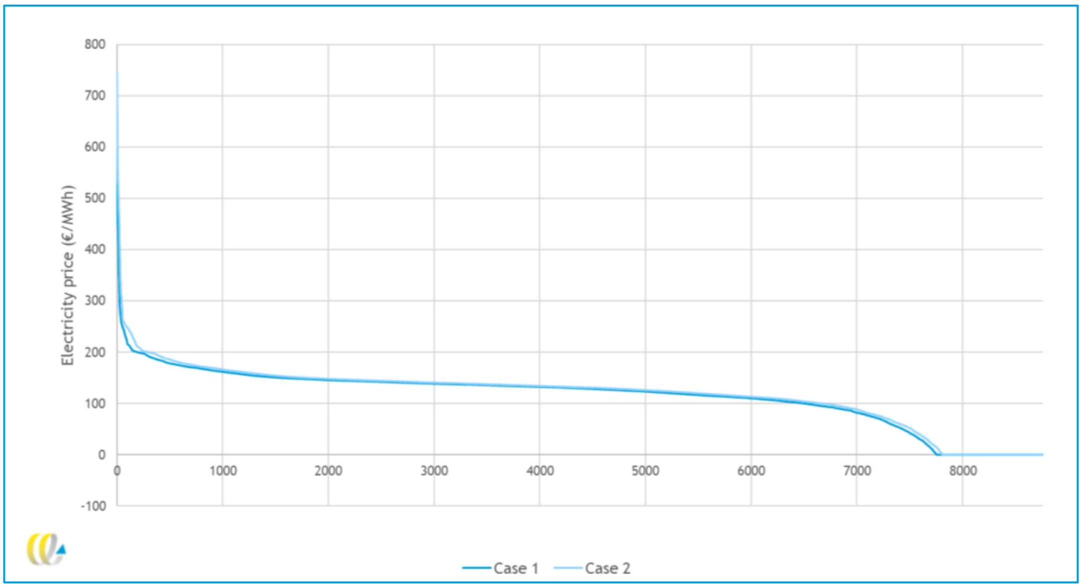


Scenario 3 and 4 - Maximal cable

Table 2 - Results of simulations for Scenario 3 and 4 - maximal cable for 2050.

Situation	Description	Average electricity price (€/MWh)
1 (min)	No electricity bought from grid/wind farm, i.e. power-to-gas facility is not running	115
2 (max)	Full capacity covered by electricity bought from grid/wind farm, i.e. power-to-gas facility operates at full capacity	119

Figure 66 - Price duration curves for Scenario 3 and 4 - maximal cable for 2050

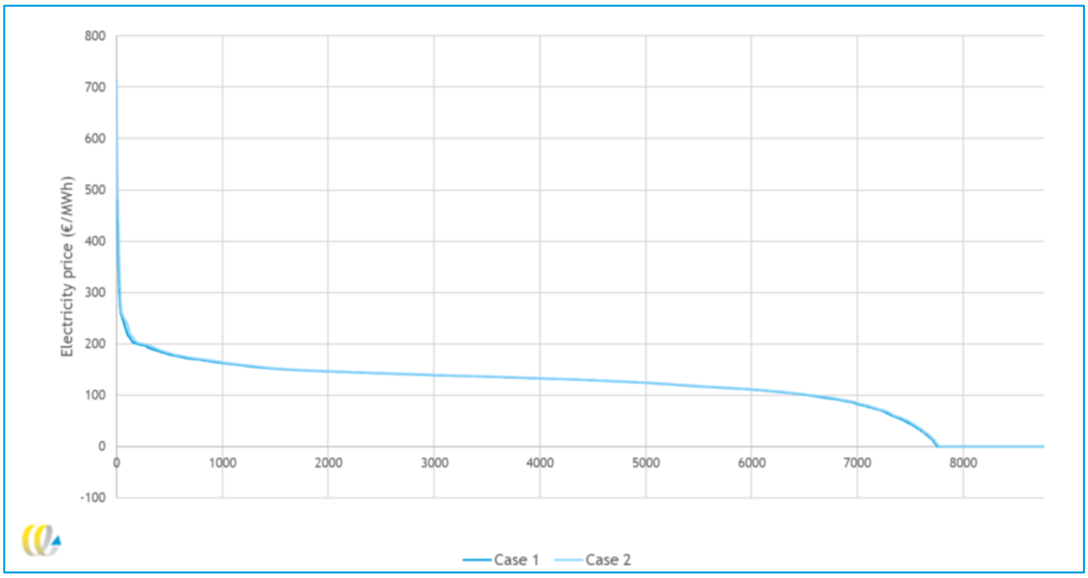


Scenario 4 - half capacity

Table 3 - Results of simulations for Scenario 4 - half capacity for 2050.

Situation	Description	Average electricity price (€/MWh)
1 (min)	Only mandatory electricity bought from wind farm by power-to-gas facility (production above 0.95 GW). No additional electricity is bought from the national grid.	115
2 (max)	Additional electricity is bought to cover the full capacity of the power-to-gas facility.	117

Figure 67 - Price duration curves for Scenario 4 - half capacity for 2050

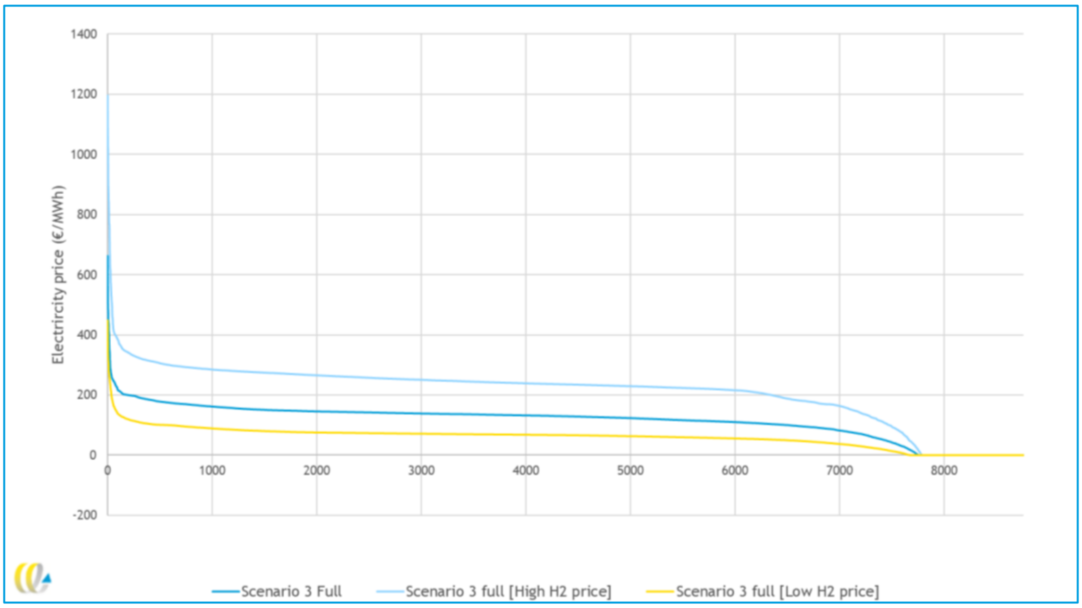


Sensitivity analysis

For the largest share of the year, the electricity market prices are set by hydrogen power plants. The electricity market prices are largely dependent of the hydrogen prices since the prices are set by the marginal costs of these plants. Since the hydrogen price in 2050 is uncertain, a sensitivity analysis is performed. For this study hydrogen prices of 1.5 €/kg and 6 €/kg are considered.

The results are shown in Figure 68. As expected, the electricity price is higher with a higher hydrogen price for a large share of the year. The hydrogen plants are not operational when renewable production is higher than the demand. Therefore, the price remains equal during these moments.

Figure 68 - Price duration sensitivity analysis for Scenario 3 and 4 – maximal cable



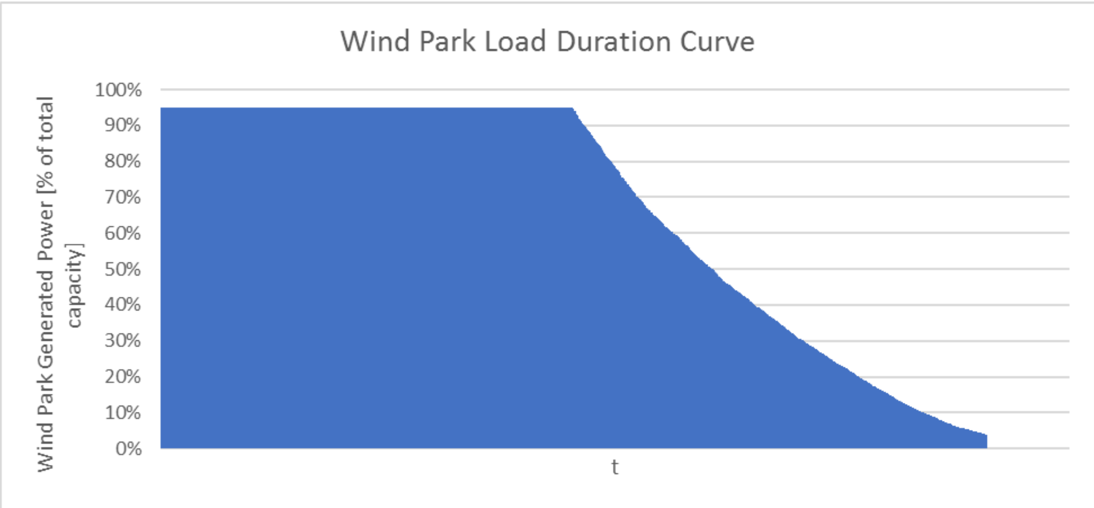
F Background of the techno-economic analysis

F.1 Impact of Energy Curtailment on the Installed Electrolyser Capacity

To answer the question whether energy curtailment can be of benefit to the business case of the power-to-gas facility/island operator, a curtailment model has been set up and the calculation results have been analysed.
The curtailment model is designed to calculate the optimal power-to-gas facility capacity in comparison to a certain wind farm capacity. The optimum is defined here as the solution with the **lowest costs of hydrogen production** (in €/kg) for a 100% conversion of offshore wind scenario.[43] The analysis was carried out on the basis of a simulation of a wind park in the IJmuiden Ver area for the period 2025-2030 and led to a total load factor of about 61 % mostly due to higher wind speeds offshore and future large turbines (Jepma & van Schot, 2017). [44,45] This seems to be a solid outcome when compared to the world's largest offshore turbine specs of the GE Haliade-X 12 MW with a mentioned load factor of 63%.[46]

The results of the simulation are shown in form of a wind duration curve in Figure 69:

Figure 69 - Normalised wind duration curve of the simulated data of a 700 MW offshore wind farm



43 Note, that the optimal solution also depends on hydrogen market prices and the project NPV. It may be more beneficial to produce a larger amount of hydrogen by increasing the electrolyser capacity when increased revenues at higher market prices outweigh the increasing LCOH.

44 Data has been retrieved from ECN as input for (Jepma & van Schot, 2017)

45 700 MW has been chosen as a standard tender size for the to be installed wind parks in near future until 2026 (Borssele, Hollandse Kust Zuid, Noord, West, Ten Noorden van Waddeneilanden). Actual approved wind park capacities differ depending on wind park design. See also RVO : Development of Offshore Wind Farms in the Netherlands

46 GE Renewable Energy : Haliade-X 12 MW offshore wind turbine platform

The profile has a maximum load capacity of 95.4% due to included cable losses and dimensioning of the wind blades to achieve a longer period of constant load despite it reaches a lower technical maximum. According to these assumptions, the maximum power-to-gas facility capacity is about 1,907 MW for 0% curtailment. Curtailment in this report is defined as a reduction of the total used energy per year [Wh/a], by decreasing the maximum power-to-gas facility capacity (i.e. 95.4% initially) [W]. The load hours are measured per ten hours. The used energy per curtailment scenario is derived from the following calculation:

Equation 5: Calculation of curtailment

$$\frac{(Energy_{curt})}{(Energy_{max})} = 100\% - c \qquad , for\ c = \ 1\%, 2\% \ldots 20\%$$

Where *c* is the percentage of curtailment of the total generation per year, $Energy_{curt}$ is the yearly summed generated energy in a curtailment scenario, $Energy_{max}$ is the yearly summed generated energy in the conventional scenario (constant, scenario where all electricity produced by the wind park is also used for the electrolysis process).

The maximum power-to-gas facility capacity is decreased compared to the maximum capacity in the conventional scenario to a value where the used electricity is decreased with *c* percent.

Input

The input parameters enter the model as exogenous parameters, defined by external sources or within the project consortium. The section below explains the composition of each input parameter.

Table 28 - Assumptions and data considered in the model

System Component	Parameter	Value	Source	Sensitivity
Wind park	Capacity	2 GW	Scenarios	No sensitivity
	Load factor[2]	59.4%	ECN	
Offshore system including island, electrolysis, pipeline & desalination unit	System CAPEX	1100 €/MW	NEC estimation	Range of -50% to +50%
	Electrolysis stack	400 €/MW	(Thomas, et al., 2016)	No sensitivity
	Electrolysis stack replacement	Varying %, based on 50,000 running hours		
	Overall OPEX	4% of CAPEX p.a.	Assumption	No sensitivity
	Offshore cost factor CAPEX (excl. stack)	200%	Assumption	No sensitivity
	Offshore cost factor electrolysis stack	200%		
	Offshore cost factor OPEX	150%		
	Efficiency	52 kWh/kg H_2	Average of 3 PEM systems (Siemens,	-10% to +10%

System Component	Parameter	Value	Source	Sensitivity
			Hydrogenics, Nel ASA)	
	LHV H_2	33.33 kWh/kg	-	-
Commodity prices	Market price electricity	50€/MWh	Conservative assumption[47]	30 €/MWh - 65 €/MWh
Financial parameters	Project period	20 years	Assumption	-
	WACC	7.2%	Assumption, explained below	Range of -70% to +70%
	Amortisation period	10 years		
	Annuity factor	1.44		

General capacity factor model calculations

Eventually, the model needs to determine the power-to-gas facility capacity at which the cost of hydrogen is the lowest. Next to the exogenous variables which have been explained earlier, we need to determine the required endogenous parameters for the levelised cost of hydrogen (LCOH calculation process. The levelised costs consist of the three main elements levelised CAPEX, O&M costs and electricity costs.
In general, the LCOH is calculated as follows:

Equation 6 - Cost components of levelised costs of hydrogen

$$LCOH\left[\frac{€}{kg}\right] = CAPEX\,[€/kg] + OPEX\,[€/kg] + Electricity\ consumption\,[€/kg]$$

Production volume of hydrogen
The total production volume of hydrogen is calculated as follows:

Equation 7 - Calculation of total hydrogen production

$$Total\ volume\ produced\,[kg] = \frac{installed\ electrolyser\ capacity\,[MW] * full\ load\ hours\ electrolyser\,[hours] * production\ period\,[years]}{electrolyser\ efficiency\left[\frac{MWh_{el}}{kg}\right]}$$

CAPEX and OPEX

The CAPEX and O&M cost calculation are calculated corresponding to the equations below. A relative reduction on the cost of stack replacements depending on the amount of production hours of the power-to-gas facility to reflect the decrease of maintenance cost with a lower load factor at high capacities (no curtailment).

Equation 8 & 9 - Calculation of levelised CAPEX and OPEX

$$CAPEX\,[€/kg] = \frac{System\ CAPEX\,[€]}{Total\ volume\ produced\left[\frac{kg}{a}\right] * project\ period},\ \text{and}\ Total\ OPEX\,[€/kg] = \frac{Total\ OPEX\,[€]}{Total\ volume\ produced\left[\frac{kg}{a}\right]},$$

[47] Compare also to Beurzen : Marktinformatie Elektra

Equation 10 & 11 - Calculation of total offshore CAPEX and OPEX

$$Offshore\ CAPEX\ [€] = \left[Offshore\ system\ capex\left[\frac{€}{MW}\right] + Offshore\ stack\ capex\left[\frac{€}{MW}\right] * stack\ replacement\ factor\ [\%]\right] * annuity\ factor * electrolyser\ capacity\ [MW]$$

$$Offshore\ OPEX\ \left[\frac{€}{a}\right] = System\ CAPEX * Overall\ OPEX * Offshore\ cost\ factor\ OPEX$$

The costs of capital are included in the annuity factor which is a financial mathematical factor for converting a capital amount into time-limited series of payments of the same amount, including interest. As it can be observed in the previous equation, the principal amount of the CAPEX of all components is multiplied by the annuity factor to calculate the final CAPEX including finance costs. The annuity factor depends on the term of the payment series and the underlying interest rate. In our calculation we assume the following: A 70% debt and 30% equity share, a net debt interest rate of 6%, an internal minimum return on equity of 10%, and an amortization period of ten years. This results in total in a weighted average cost of capital (WACC) of about 7.2%.

Electricity consumption

The determination of the applicable electricity price requires some additional context related to the business model of the wind park operator. In the considered case of a single connection between the wind park and the energy island, the wind park operator has to rely on a single customer limiting his market reach compared to a conventional grid connection to shore that enables access to a larger market with multiple consumers. We assume that the power-to-gas facility operator is in any case limited to a single supplier of electricity, being the offshore wind park at IJmuiden Ver.

This impacts the model calculation to the extent that the optimization of power-to-gas facility capacity, which means potentially less capacity and less electricity consumption, must not discriminate the business case of the wind park operator. In other words, the power-to-gas facility operator has to pay for all the electricity that is produced by the wind park operator, but does not use all of it. Therefore, the price he pays for the used electricity is higher. The composition of the actual electricity price paid by the power-to-gas facility operator is further explained in the next section.

Equation 12 - Calculation of the power-to-gas facility operator's annual energy costs in the conventional case

$$Annual\ energy\ costs_{conventional}\ [M€] = WP\ capacity[MW] * WP\ full\ load\ hours\ [hours] * market\ price\ electricity\ [\frac{€}{MWh}]$$

Compensation calculation

As explained previously, the actual electricity price to be paid by the power-to-gas facility operator differs in our case from the market price. This is depicted in the following equation:

Equation 13 - Calculation of the power-to-gas facility operator's annual energy costs in the unconventional case

$$\boldsymbol{Annual\ energy\ costs_{unconventional}}\ [\boldsymbol{M€}] = \boldsymbol{Electrolyser\ capacity}\ [\boldsymbol{MW}] * \boldsymbol{full\ load\ hours}\ [\boldsymbol{hours}] * (\boldsymbol{market\ price\ electricity} + \boldsymbol{compensation})[\frac{€}{\boldsymbol{MWh}}]$$

And $Annual\ energy\ costs_{conventional} = Annual\ energy\ costs_{unconventional}$

To comply to the parity of conventional and unconventional revenue streams, the interdependent factors that need to be quantified are:

1. The curtailed energy share of total energy generation determined as a model input and the main parameter for optimization. The optimization range has been set from 0% to 20% curtailment of generated electricity (MWh).
2. The average market price for electricity that is a fixed model input. The base price is set at 50€/MWh with a sensitivity range of 30 - 55€/MWh
3. The compensation paid to the wind farm operator for less consumed electricity to achieve revenue parity.

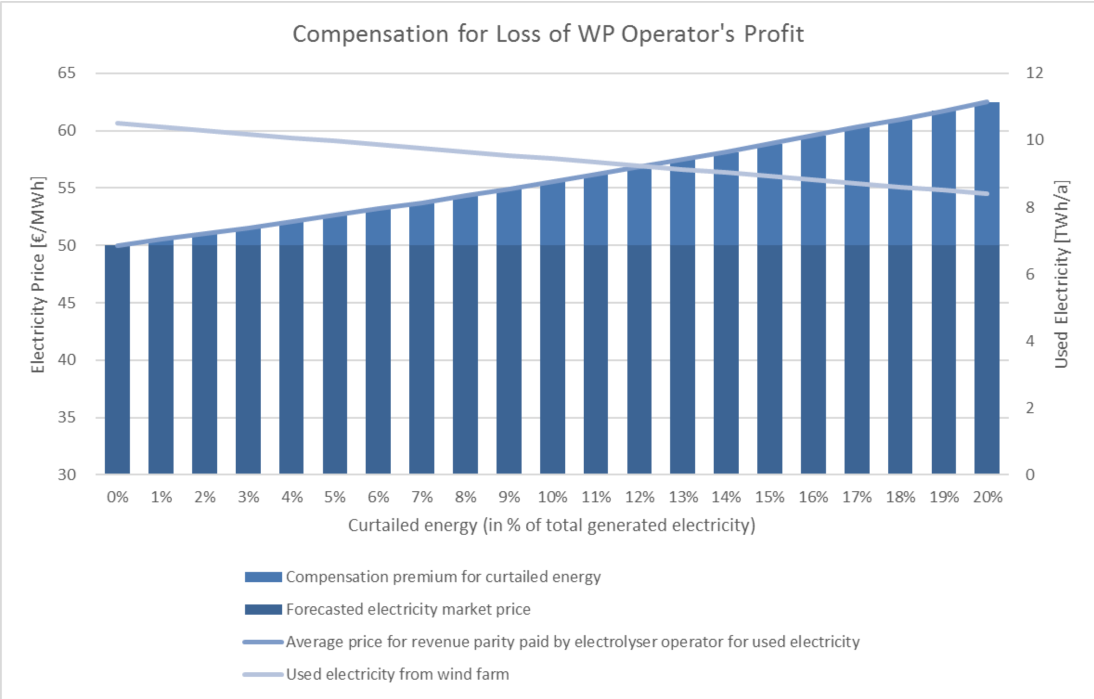
With increasing amounts of curtailed energy it becomes obvious that the costs of the wind farm operator eventually increase (as soon as more is curtailed than electricity at a negative revenue). The compensation is then calculated according to :

Equation 14 - Calculation of the electricity compensation for the wind park operator

$$Compensation = \frac{Annual\ cost_{conventional}\ [M€] - Annual\ cost_{unconventional}\ [M€]}{[Electrolyser\ capacity\ [MW] * full\ load\ hours\ [hours]]}$$

Figure 70 shows the share of conventional market price and the required compensation to achieve revenue parity for the wind park operator over the given range of curtailed energy. The compensation ranges then from 0 to some 13 EUR per MWh of used electricity.

Figure 70 - Development of average price for revenue parity with increasing curtailment

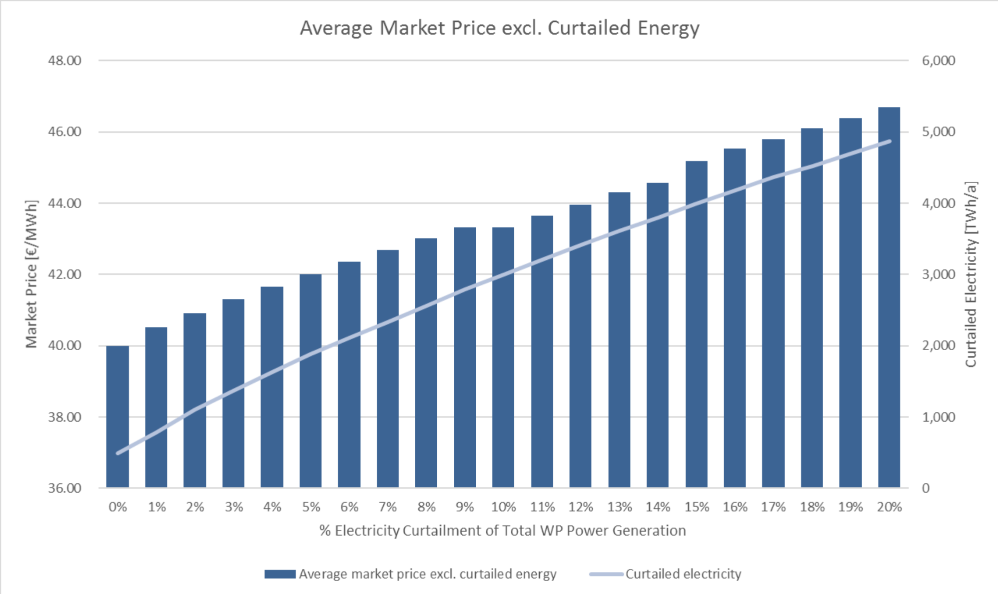


This finding is also in line from what can be expected based on historic data, showing that the average price paid by the electricity consumer rises with increasing shares of curtailment. According to APX data (2004-2014), the average price paid can be defined as the average APX value below the curtailment percentile (e.g. 5% curtailment → market price equals the average APX value below the 5% percentile).[48]

Accordingly, the average prices increase as expected (Figure 71). With the influx of more intermittent energy, negative energy prices might become present at the lower curtailment percentile. This would imply that the wind farm operator has to pay in order to provide electricity to the market. However, more advanced models for forecasting the electricity price would be required to define a respective scenario.

[48] The underlying assumption here is that the value of curtailed energy is the lowest and thus corresponds to the lowest APX market prices.

Figure 71 - Effect of curtailing electricity on the historic APX prices



Capacity optimization

The previous sections provide all required information for the optimization process where with smaller power-to-gas facility capacities the decreasing costs related to the capital and O&M costs of the power-to-gas facility are set against the decreasing volumes of produced hydrogen and higher specific electricity costs. The power-to-gas facility capacity is directly linked to the curtailment percentage. For this purpose we compare the cost price per kg of hydrogen for the curtailment range and choose the optimal capacity based on the lowest cost price.

Optimisation

In the base case the curtailment of the windfarm does not lead to a lower hydrogen cost price. The components of the cost price (CAPEX, OPEX and electricity price) are displayed in.

Figure 72 - Outcomes optimisation capacity factor under base assumptions

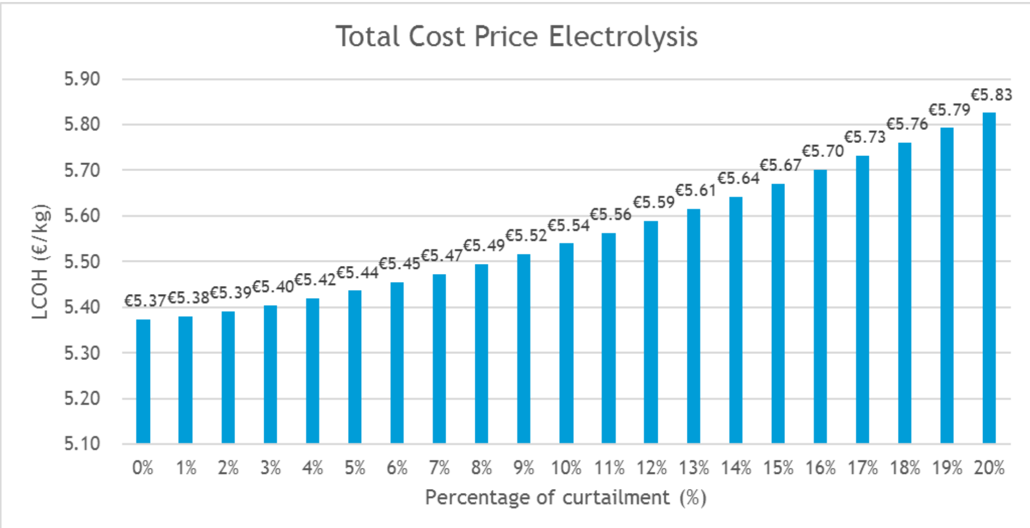
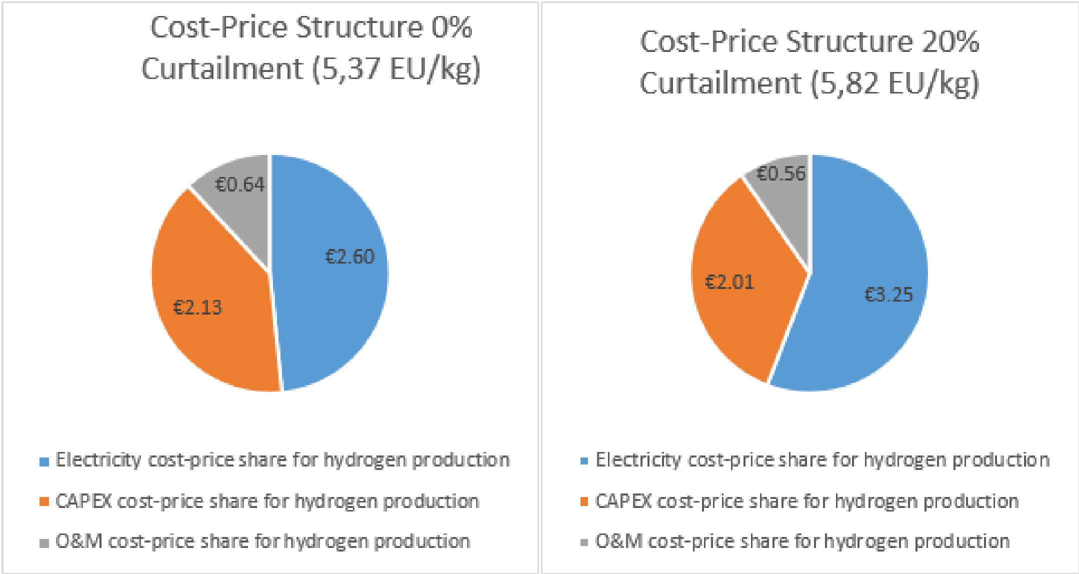


Figure 73 - Distribution hydrogen production for 0% curtailment and for 20% curtailment under base assumptions



General sensitivity analysis

To obtain more insight in the robustness of the results, a sensitivity analysis is performed. Due to considerable uncertainty of parameters such as future electrolysers (efficiency and CAPEX) along with the electricity price and WACC, these factors are independently tested for their impact on the results (see Table 29). What can be observed is that the electricity price has some impact on the percentage of curtailment, where the amount of effective curtailment increases over a decreasing electricity price (as the premium for the wind operator also decreases for their less valuable electricity). The impact is not immense, as the curtailment only ranges between 0 and 5% for a future market price range of 20-65€/MWh. It should be noted that the optimal percentage of curtailment increases significantly (Figure 74) once the electricity price decreases further below 20 €, since the premium decreases and the relative savings on the electrolyser CAPEX have a larger impact on the hydrogen cost price. The CAPEX of the system shows to be of less impact. The high uncertainty for offshore electrolyser costs are reflected in an interval of +50%/-50% resulting in a curtailment range of 0% in the best case, and 1% in the high CAPEX scenario. The impacts of the efficiency and the WACC sensitivities on the amount of curtailment are minor.

Figure 74 - Depiction of the lowest hydrogen prices per electricity price scenario, and the corresponding percentage of curtailment to achieve this (other parameters under base assumptions)

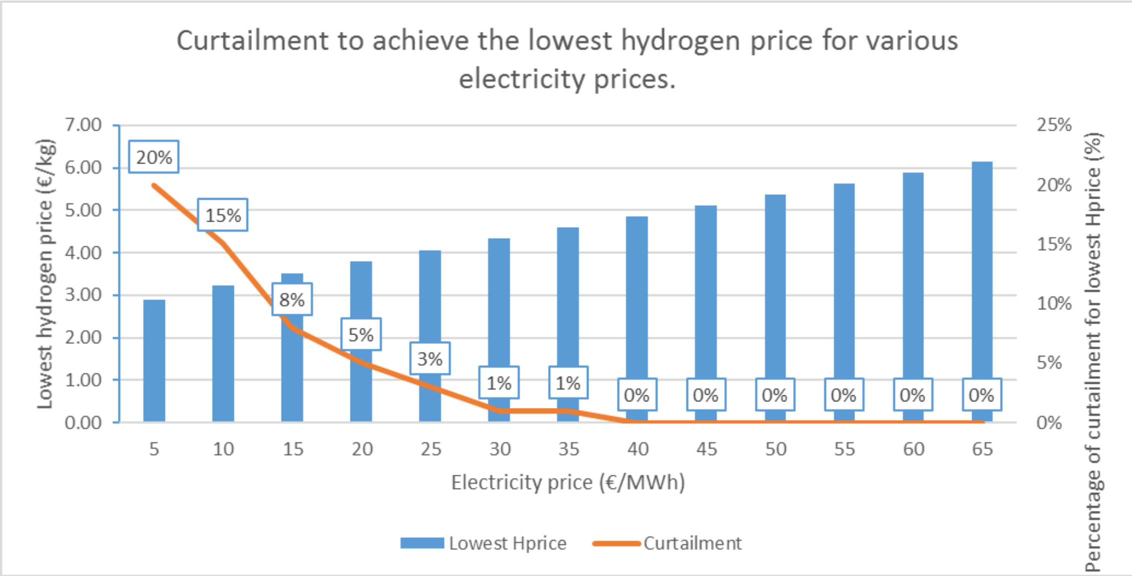


Table 29 - Sensitivities of the model

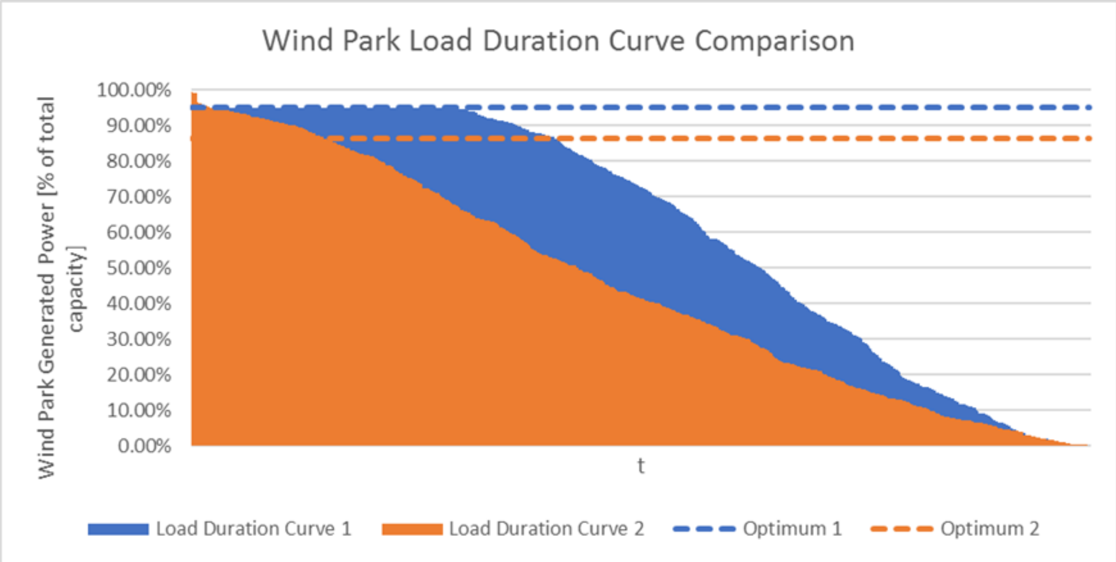
Parameter	Parameter Value	Sensitivity	Hydrogen Cost Price	Optimal Curtailment
Electricity cost price	20 €/MWh	-30 €/MWh	3.79	5%
	30 €/MWh	-20 €/MWh	4.33	1%
	40 €/MWh	-10 €/MWh	4.85	0%
	50 €/MWh	-	5.37	0%
	60 €/MWh	+10 €/MWh	5.89	0%
	65 €/MWh	+20 €/MWh	6.15	0%
CAPEX system(€/kW)	1050	+50%	6.04	1%
	700	0	5.37	0%
	350	-50%	4.70	0%
WACC (%)	12.2%	+70%	5.75	0%
	7.2%	0	5.37	0%
	2.2%	-70%	5.03	0%
Efficiency (kWh/kg)	46.8	-10%	4.84	0%
	52	0	5.37	0%
	57.2	+10%	5.91	0%

Wind profile sensitivity

Following the capacity optimisation analysis, CE Delft provided NEC with an additional wind profile as an extra input for the sensitivity analysis. Below we briefly describe the outcomes of that sensitivity and reflect on its impact on our previous analysis.
Figure 75 below shows the original wind duration curve and optimal power-to-gas facility capacity (Wind Profile 1 & Optimum 1) compared to the new profile and optimum based on CE Delft's provided data (Wind Profile 2 & Optimum 2). Using the new data set for the optimization model demonstrates in the base case that:

– Wind Profile 2 is less evenly distributed than Wind Profile 1 and shows little hours of the wind park at full capacity.
– Based on Wind Profile 2 the full load hours of the wind park decrease by about 1,000 and result in a wind park capacity factor of 44.9% compared to the previous capacity factor of 59.9%.
– The optimal power-to-gas facility capacity resulting in the lowest cost price of hydrogen is now some 79% and about 5% of total curtailed energy, in contrast to the preceding results of 95.4% power-to-gas facility capacity and 0% total curtailed energy.
– Respectively, the cost price of producing hydrogen increases from 5.37 (Case 1) to 5.77 EUR per kilogram of hydrogen (Case 2).

Figure 75 - Wind duration profile comparison including the optimal power-to-gas facility capacity

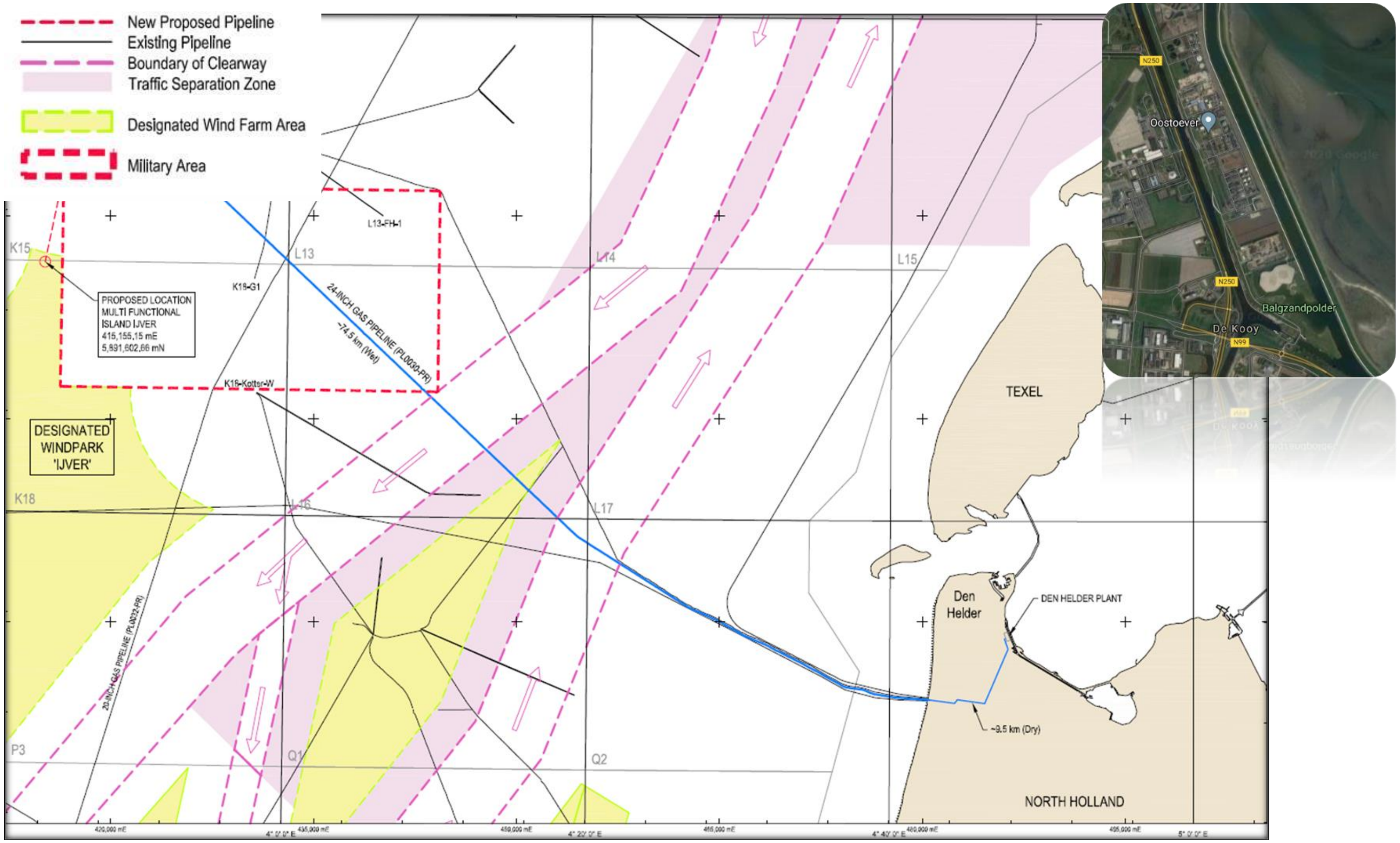


Altogether, one may conclude that these results are mainly due to the more steeply decreasing wind duration curve of the new data set. When curtailment is considered, this changes the relation between savings on the power-to-gas facility side and the decreasing volumes of available electricity on the other side. That difference becomes more clear when taking a look at the optimal solution of the new base case: Now, relatively large reductions in power-to-gas facility capacity and therefore large savings on the CAPEX (about 20% reduction) side result in just little curtailed energy (some 5%). This is just nearly half the energy curtailed compared to the earlier outcomes at similar capacity.

Nevertheless, the overall outcome in terms of hydrogen cost price is less attractive for the island operator due to the significant reduction in generated electricity. We presume that this is mostly based on a different approach of the data set. In that sense the original method has a more futuristic character, rather focussed on how a future system may look like with new wind turbine technology at larger distances to shore and higher wind speeds on average. The latter data set basically mirrors the historic and current situation, including actual generation data of already existing wind farms but with turbine technology which may be outdated in near future and wind speeds which are significantly below the far offshore situation.

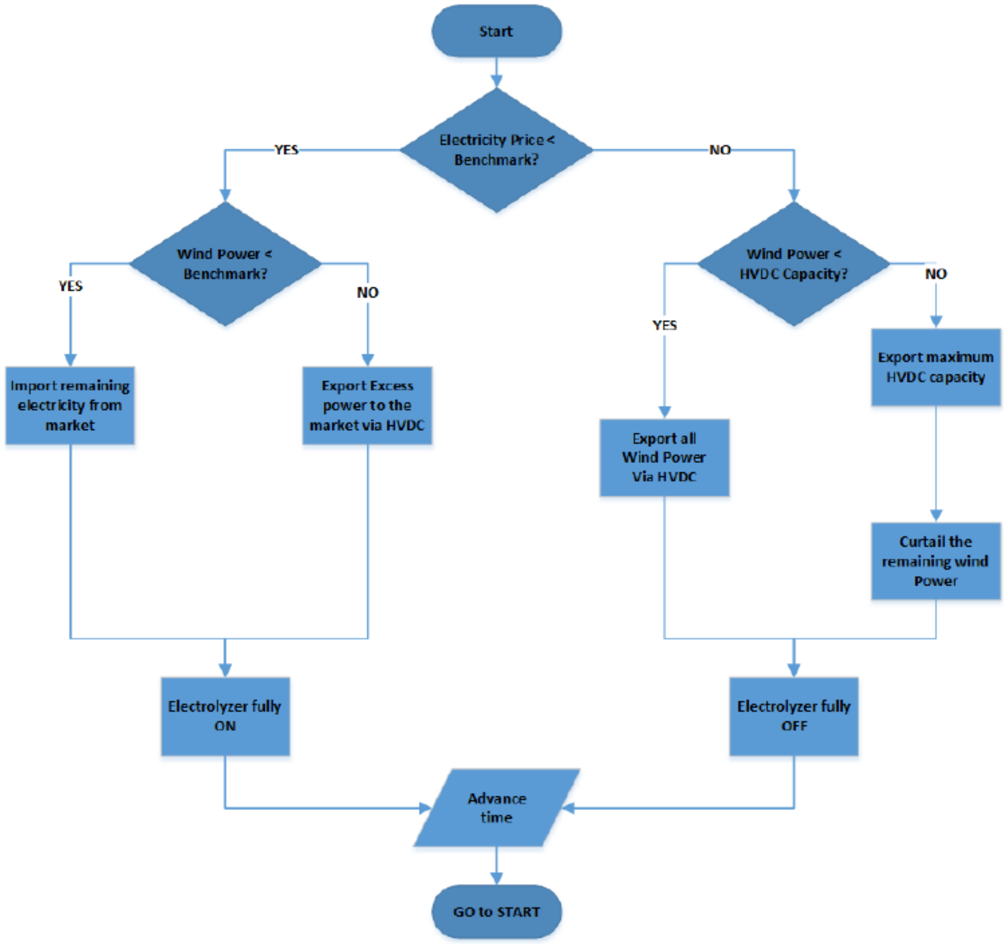
Considering these aspects, we deduce that maintaining the original data set goes more in line with the context of this project where we try to illustrate a future system in 2030 with changed conditions. Also, the difference in results should not be understood as a contradiction but rather call attention to the urgent need of wind turbine technology improvement and respective uncertainties.

F.2 Key Plan Pipeline Infrastructure



F.3 Energy Management Strategy Scenario 4a (offshore hybrid scenario)

The wind farm energy is divided between the energy carriers according to a rule-based energy management strategy that aims to maximize revenues. If the electricity price is below the benchmark calculated in the previous section (i.e. Electricity price favourable for Hydrogen production), then the power-to-gas facility is turned on to its full capacity, importing additional energy from the market when necessary. On the other hand, when electricity prices are not favourable for Hydrogen production, Wind power is transported via the HVDC system and the power-to-gas facility is turned on. If the power exceeds the HVDC transmission capacity, then the extra power is curtailed.
The cost of curtailment is incurred by the power-to-gas facility operator at a fixed cost of 40 [€/MWh]. A flowchart of the energy strategy implementation is provided below:



F.4 Summary of scenario results

Table 30 - Project key figures (hydrogen market price = 1.5 €/kg)

Result	Unit	Scenario 1	Scenario 2	Scenario 3	Scenario 4b
NPV	[MEUR]	-6,376	-5,514	-1,995	-2,187
Offshore structure	*[MEUR]*	*-946*	*-585*	*-946*	*-585*
Offshore power conversion	*[MEUR]*	*-373*	*-*	*-373*	*-373*
Electric cable	*[MEUR]*	*-450*	*-*	*-450*	*-450*
Onshore substation	*[MEUR]*	*-397*	*-*	*-397*	*-397*
Green P2G	*[MEUR]*	*-1,204*	*-1,869*	*-929*	*-1,457*
Cost electricity P2G	*[MEUR]*	*-4,737*	*-4,727*	*-159*	*-160*
Cost electricity WP-Market	*[MEUR]*	*-*	*-*	*-3,412*	*-3,412*
Revenue electricity	*[MEUR]*	*-*	*-*	*5,042*	*5,042*
Revenue H^2	*[MEUR]*	*3,251*	*3,103*	*862*	*874*
G&A	*[MEUR]*	*-1,519*	*-1,436*	*-1,233*	*-1,268*
LCOH	[€/kg]	5.61	5.26	4.18	5.06
LCOE	[€/MWh]	-	-	98.52	89.32
Electricity provided by wind park	[GWh]	92,266	92,266	21,334	21,334
Electricity provided by market	[GWh]	7,100	-	4,892	4,798
Electricity provided for market	[GWh]	-	-	60,838	60,838
Hydrogen produced	[ton]	1,715,962	1,637,094	455,618	462,706
Average P2G capacity factor	[%]	69%	64%	18%	18%

Table 31 - Project key figures (hydrogen market price = 6.0 €/kg)

Result	Unit	Scenario 1	Scenario 2	Scenario 3	Scenario 4b
NPV	[MEUR]	4,103	3,796	7,727	7,441
Offshore structure	*[MEUR]*	-946	-585	-946	-585
Offshore power conversion	*[MEUR]*	-373	-	-373	-373
Electric cable	*[MEUR]*	-450	-	-450	-450
Onshore substation	*[MEUR]*	-397	-	-397	-397
Green P2G	*[MEUR]*	-1,245	-1,869	-1,081	-1,685
Cost electricity P2G	*[MEUR]*	-6,554	-4,727	-5,408	-5,443
Cost electricity WP-Market	*[MEUR]*	-	-	-1,567	-1,567
Revenue electricity	*[MEUR]*	-	-	8,281	8,281
Revenue H^2	*[MEUR]*	15,962	12,413	11,595	11,632
G&A	*[MEUR]*	-1,894	-1,436	-1,925	-1,970
LCOH	[€/kg]	5.57	5.26	5.81	5.88
LCOE	[€/MWh]	-	-	110.76	104.88
Electricity provided by wind park	[GWh]	92,266	92,266	62,227	62,227
Electricity provided by market	[GWh]	30,023	-	29,169	28,613
Electricity provided for market	[GWh]	-	-	25,764	25,764
Hydrogen produced	[ton]	2,130,950	1,637,094	1,598,676	1,605,961
Average P2G capacity factor	[%]	82%	64%	55%	55%

G Stakeholder engagement

An early workshop was organised on the 10th of July 2019. Approximately 20 parties participated in this workshop.

A second workshop was planned for Spring 2020. However, due to the covid-19 crisis that set on in March 2020, this workshop could not be held. Instead, interviews were carried out in April and early May 2020. In total, 25 parties were contacted. The following parties have actively participated in the interviews:
- EBN;
- Greenpeace;
- Ministries of Economic Affairs and Climate Policy, Infrastructure and Water Management, and Agriculture, Nature and Food Quality;
- Natuurmonumenten;
- Nexstep;
- Nogepa;
- NWEA;
- OneDyas;
- Ørsted;
- TenneT;
- TU Delft;
- Vissersbond.

The input of these parties has been very valuable for the non-technical analysis.