North Sea Energy

A vision on hydrogen potential from the North Sea

D1.6 Offshore Hydrogen roadmap
D. 1.7 Analysis of current offshore market failures and the respective role of existing policy
D. 1.8 Recommendations on required policies to achieve a socially optimal state

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Summary

Cost reductions and experience gained in North Sea are opening up a huge renewable resource potential resulting in capacity projections for the whole North Sea of some 180 GW by 2050. This projected capacity will rapidly increase the share of intermittent sources of energy production and will result in significantly more flexibility to guarantee the required grid balancing condition and to provide balance for demand and supply on the long term. This report discusses the impact of the increasing volumes of offshore wind energy produced at the Dutch part of the North Sea on the offshore energy system including its infrastructure. The report starts from the notion that hydrogen will very likely play an important role in the future energy (and zero carbon feedstock) system not only by providing flexibility, but also to fulfil the increasing need for carbon free molecules for various purpose. The justification for this lies within a number of exiting scenarios all portraying possible future hydrogen demand and supply scenarios (e.g. (Afman, 2017) (Gasunie and TenneT, 2019) (WerkgroepH2, 2019) (DBI, 2020), (IEA, World Energy Outlook, 2019). More specific, the first part of the report describes the strategic role of the North Sea area for hydrogen production and transport. The second part of the report focusses on the governance and intervention mechanisms that are needed to overcome the identified economic distortions, both in system integration and the development of a hydrogen market.

The assessment of the required volume of hydrogen produced from offshore wind just for flexibility purposes is relatively complex because it depends on a number of factors, such as: electricity demand, hydrogen demand, electricity supply, etc. By taking all these factors into account various simulations (highly based on the Infrastructure Outlook 2050) have been carried out to determine the share of offshore wind that in the optimum energy system integration would need to be converted into hydrogen (either onshore or offshore). The weighing of the costs of onshore versus the costs of the offshore production alternative includes on the one hand the higher costs of installation and maintenance of electrolysers systems offshore and on the other hand the potential savings on transport infrastructure. The study concluded, based on so-called hybrid scenarios, i.e. allowing wind energy to be transported to shore either as electricity or as hydrogen, that - at the current prices for hydrogen and without the investors being reimbursed for public savings on electricity grid investment - there is not much evidence that offshore hydrogen production will be an economically interesting option before 2030. This is in line with the current policy plans of the Netherlands' government to predominantly install the projected 11.5 GW of offshore wind capacity via electricity grid connections, probably in conjunction with AC/DC and DC/AC conversion. Hence, unless serious policies and measures are taken at short notice to improve the system case of offshore conversion of wind power into hydrogen, the start of hydrogen production in de period up to 2030 will most likely be concentrated on onshore locations. Apart from economic reasons, there may be other reasons for choosing either offshore or onshore hydrogen production. The LCA of P2G from D.4.2 indicated, for instance, that onshore hydrogen production can be slightly more preferable, due to the potential to effectively re-use the by-products. Also other environmental factors may affect the optimum solutions, but assessing ecological effects was outside the scope of this study.

The outcomes for post 2030 period turned out to be quite different from those for the 2020-2030 period. For the period 2030-2050, at least some additional 10 to 20 GW offshore wind capacity will need to be installed per decade to realise the Dutch ambitions for extending offshore wind capacity by 2050. Based on our NSE – Net van de Toekomst scenarios, this rapid increase in offshore wind results in the need for more flexibility and a higher conversion share of offshore wind into hydrogen in this period (in the range between 43% and 49%). The simulations indicated that, while considering an offshore cost factor of 175%, offshore hydrogen production does generate positive returns in comparison to onshore hydrogen production in the post 2030 period. The concept of creating offshore energy conversion islands – that obviously could provide many other energy and non-energy functions as well – turns out to become the most feasible option in the post 2030 period. The main conditions for these investments to generate a positive business case are if sufficient economics of scale can be generated, so if wind capacities are sizeable enough, and whether there is sufficient distance from shore such that grid savings become substantial enough. We found for the post 2030 period that for higher wind farm capacities in the order of 6 GW, energy islands become economically very favourable, the more they are located further (more than 100 km) from shore. However, if (sandy) island construction would not be feasible due to for instance nature conservations, than existing platforms located further offshore (e.g. >120km) can be considered to be interesting potential locations for hybrid offshore hydrogen production.

The option of combining conversion with admixing the hydrogen to the natural gas is problematic on the longer term. A main reason is linked to the assumption that admixing rates will remain technically restrained to e.g. some 15% only. Under such a regime the flow of hydrogen is simply too low to get to an economically feasible result. Also, like in the hybrid case for the 2030-2050 period, installing new platforms and pipeline systems dedicated for hybrid offshore hydrogen production is not a feasible option.

Dedicated hydrogen production - converting all wind power into hydrogen so that an electricity grid connection between the offshore wind farm and shore is no longer needed - on the whole, shows a greater preference for offshore conversion configurations. This is logical because grid savings will be larger and overall the system is simpler, although less flexible, than the cost for the onshore system are slightly higher. This explains for instance also the finding that re-use of existing platforms for dedicated hydrogen production already generates positive returns if located at shorter distance from shore than comparable hybrid cases.
Although, the pre-2030 period shows an economic preference for onshore hydrogen conversion, it seems unlikely that during the next decade in the Netherlands no progress will be made towards setting up and installing offshore conversion capacity. In fact concrete pilots and even larger-scale initiatives on this are now already (2019) initiated or are in preparation by some North Sea operators. Operators are expected to prepare for that and already take action well in advance to prepare for their own business and competitive future, while gaining expertise before commercial offshore hydrogen production can be reached. Such preparatory stages can easily take about a decade, especially under the challenging offshore conditions at hand. A fortunate point in this regard is that so far some 900MW offshore wind capacity to be installed by 2030 has not yet been assigned to a particular location. If that capacity would be used for experimenting with offshore conversion options/technologies, there still are some degrees of freedom to find the most suitable location for this.
What does all this mean for policies and measures needed to proceed? For the specific situation of the North Sea offshore energy system, it is clear that without a serious and balanced set of policies and measures, much of the North Sea energy conversion activity will not come off the ground, much later off the ground, or will develop in a way that is suboptimal from the social welfare perspective. Specific policies and measures that therefore seem to be in order, except from the more generic ones dealing with externalities mentioned above, are first of all to make sure that operators and investors in offshore wind power conversion (to hydrogen) are supported in the initial stages which can be characterised currently as a valley-of-death. Offshore conversion, may indeed have a good economic future and in fact can turn out to be indispensable to not only generate sufficient levels of carbon free hydrogen that the market will need, but is also indispensable in dealing with the threat of power market congestion, insufficient balancing, or overly expensive extension. In order for offshore conversion, probably starting on oil and gas platforms to be decommissioned and later on followed by artificial islands, to get off the ground in time, operators that take the lead by setting up early initiatives would need to be supported via dedicated support schemes for pilots and demonstration projects, such that in the course of the next decade the knowledge base for offshore conversion is developed well enough to take advantage from the subsequent business case and societal positive impact. Obviously, such support could be provided in various ways, e.g. through tender conditions, specific support schemes for offshore conversion, support in platform adjustment, fiscal measures, etc. All such measures would, however, have in common that the next decade this technology becomes well-developed, and the operators ready to offshore conversion at significant scale from about 2030 onwards. Next to this, given the usual lead times required for preparing the significant investments for infrastructure, it is important that all the legal and regulatory issues that may emerge are addressed well in advance. It is important that infrastructure options will be timely available and that issues such as licenses, ownership, responsibility, risk and safety management, and environmental issues can be operated smoothly. Due to the lack of experience with offshore hydrogen production, it is likely to be a relatively complex set of policies, measures, and regulations that will need to be set up to make the transport system work, and work in time. Hydrogen will eventually need to be put on the market, which may have implications for standards and norms with respect to gas quality, pressure, etc., which in its turn may have implications for the quality of the gas infrastructure facilities and related equipment. All this may require rules and regulations related to quality, pressure, flow speed, corrosion, etc., which all will have to be taken care of, especially insofar as the saline environment will have an impact on such standards and norms.

Introduction

The Netherlands' energy mix will have to change drastically in order to be able to achieve the future national CO_2 emission reduction targets. Offshore wind is expected to play an important role in that mix with total capacity levels up to 53 to 60GW by 2050 (Gasunie and TenneT, 2019) (Wittebeen & Bos, 2019) (Michiel Müller) (Windeurope, 2019). The Dutch government assumes that this process will be supported by a declining costs trend according to which CAPEX per MW installed may come (further) down to LCOE levels in the order of 30 - 40€/MWh (Klimaatberaad, 2019). Installing such large capacities of offshore wind creates a number of challenges. First, it requires careful spatial and stakeholder planning such that the other offshore functionalities (nature, fishery, shipping, etc.) are sufficiently respected, and overall use of offshore space remains in balance. Second the design of the energy system and the investments needed to that end will have to be thought through well in order to optimise the overall energy value chain and optimally satisfy the energy targets, greening, securing supply and guaranteeing affordability.

One of the challenges of the energy system relates to the optimal location of large-scale energy conversion (onshore or offshore) and how that may affect energy transport and storage modalities and costs. Because of its clear link with this report, it is worth mentioning that quite recently TenneT and Gasunie published the 'Infrastructure Outlook 2050', their first joint long-term vision on the future optimal nexus between P2G conversion and the onshore energy infrastructure (Gasunie and TenneT, 2019). The Outlook states first that the future volume of gas that needs to be transported will be comparable to, or potentially even higher, than today (Gasunie and TenneT, 2019, p. 30), but that transport needs for electricity may increase by some 30%. The latter does not only require planning of about 10 to 15 years in advance (Magazine, 2019)[1], but also involves costs in the order of €20 and €60 bn for the high voltage onshore and offshore grid, respectively.[2] To these costs, costs related to the required extension of the distribution grid will need to be added. Because on average costs per unit of energy transported of gas-grids are (much) less than those of e-grids and because the same difference applies even stronger for energy storage, it is logical that under specific conditions it may be cost-effective to convert electricity into molecules. Also other reasons may make this conversion desirable, such as the composition of (future) energy demand, lead times, acceptance, etc. In fact, in a fully sustainable energy system, conversion is part of the optimisation such that molecules and electrons complement each other to keep the system flexible, robust, reliable and affordable.

In this regard, one of the main conclusions of the Outlook mentioned was *"converting renewable energy to hydrogen at locations close to the renewable production facilities will relieve bottlenecks in the electricity infrastructure, without causing problems for the gas infrastructure"* (Gasunie and TenneT, 2019, p. 35). A serious limitation of the Outlook is that offshore infrastructure was not included in the optimisation process, probably because the offshore gas infrastructure does not belong to the TSOs' asset base (although it seems that an extension of the Infrastructure Outlook 2050 to include the offshore domain is prepared). That is why in this report we will focus on discussing how rapidly increasing amounts of North Sea wind energy may affect offshore infrastructure needs in the Netherlands thereby relying scenario-wise on the Infrastructure Outlook 2050 where the onshore energy system was already optimised. In doing so, the following research questions will be addressed:

- **What is the strategic potential of the North Sea area for hydrogen production and transport; and what steps are required to get to an optimal offshore hydrogen system rollout?**
- **What governance and intervention mechanisms are needed to overcome identified market distortions preventing both optimal energy system integration and the development of hydrogen markets in general?**

The outline of the report is as follows. Chapter 2 provides an overview of the approach used to assess the strategic role of the North Sea area for hydrogen production and transport. The scenarios considered are in line with existing scenarios ((Gasunie and TenneT, 2019) (WerkgroepH2, 2019) and (Matthijsen, 2018)) and discussed in Chapter 3. Chapter 4 deals with the existing and future infrastructure needs to get to an effective offshore hydrogen production roll-out, thereby distinguishing

[1] Interview with Ben Voorhorst, COO TenneT
[2] Energy Transition Model – national management scenario used as input for the Infrastructure Outlook 2050.https://pro.energytransitionmodel.com/scenario/costs/infrastructure/high-voltage-network

the system boundaries of hybrid and dedicated hydrogen production. While highlighting the uncertainty of the offshore costs factor, Chapter 5 comprises a survey of the main results and a perspective (incl. a visualisation) on the potential role of offshore infrastructure across the various scenarios. The optimal integration of the electric and molecular energy systems requires governance and timely intervention. The various market failures are discussed in Chapter 6 and the intervention mechanisms in Chapter 7. The conclusions are summarised in Chapter 8.

Approach

This section describes the approach taken towards an offshore hydrogen roadmap by structuring the five consecutive steps needed for answering the first research question (Figure 1). In doing so, the most important assumptions, input data, and results as reported in the Infrastructure Outlook 2050 mentioned form the basis of the analysis. Key elements are, for instance:

- direct use of electricity in sectors where electrification is feasible is the most preferred option;
- carbon free hydrogen is produced either by converting surpluses of offshore wind energy, or if such production is required by flexibility needs on the power market (e.g. to prevent or overcome e-grid congestion);
- hybrid energy systems use both a molecular (carbon free hydrogen) and electric transmission systems to connect offshore wind farms with shore; dedicated energy system, instead, only uses a molecular transmission system for that purpose.

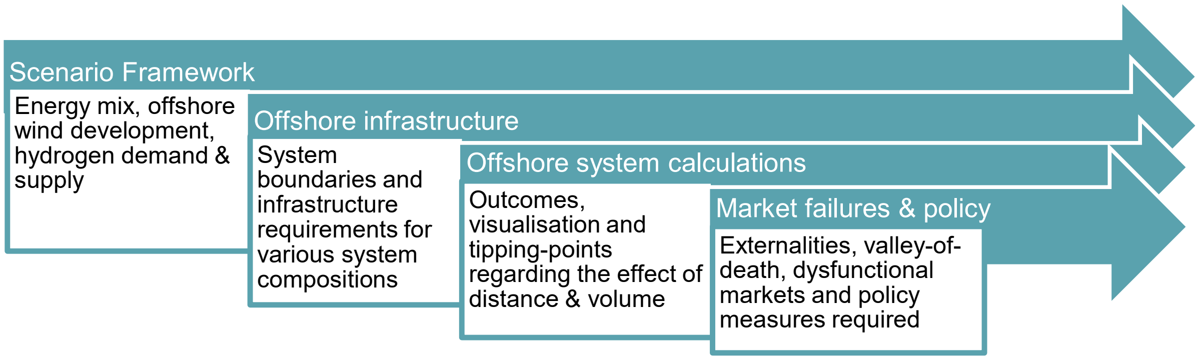

Figure 1: Overall study set-up

Step 1: Scenario framework

The scenarios of Infrastructure Outlook 2050 have been used as a starting point, but only those in which either system management is carried out at a national level and by the national government (largely based on the 'National Management' scenario in the NvdT study of CE Delft), or at a local level and by the local government (largely based on the 'Regional Management' scenario in the same NvdT study). Alternative scenarios assume a higher influx of offshore wind and a higher demand for hydrogen. Parameter values were derived from the PBL-outlook (Matthijsen, 2018) and the hydrogen demand scenarios from the Hydrogen Workgroup of the national Climate Agreement (WerkgroepH2, 2019).[3] All scenarios used are in line with the 2050 decarbonisation target to reduce greenhouse gas emissions by 95% compared to 1990 levels.

Step 2: Offshore infrastructure

Each scenario considers two energy carriers (hydrogen or electricity) and two production systems (hybrid and dedicated).[4] These production systems require a different design of the offshore infrastructure, because only hybrid systems have both an electric and molecular connection with the onshore energy system. Next to that, the location of the electrolysis process, which can be either offshore (on an island/platform) or onshore, has great impact on the offshore infrastructure design. The economic preference for either onshore or offshore hydrogen production is analysed by the weighing of the various infrastructure components. This step addresses the assumptions taken for various offshore infrastructure components, which are mostly gathered in cooperation with the other WPs. For instance, the electric system costs are assessed by the TOET-model developed in D3.8, the island substructure costs per MW of electrolyser capacity installed are addressed in D3.8 as well as in D3.2

[3] The werkgroep H2 has not yet considered the potential growth in hydrogen demand from bunker fuels.

[4] A hybrid system considers the generation and transport of both electricity and hydrogen, whereas a dedicated system focusses on hydrogen transport only.

and the techno-economic model for offshore pipelines is developed jointly with activities reported in WP 3.3.

Step 3: Offshore system calculations

The offshore system outcomes are presented via a single (KPI-like) value, namely the allowable offshore cost factor for offshore hydrogen production. Offshore hydrogen production is expected to be more expensive than onshore production because offshore conditions generally increase installation, operation and maintenance costs. However, despite cost differential experiences from gas production on offshore platforms, the Maasvlakte, or the Dutch islands, still much is unknown about actual costs of offshore hydrogen production. That is why the focus has been on the so-called allowable offshore cost factor describing the level of additional costs at which offshore production breaks-even with onshore production. Based on this factor, stakeholders (both gas and wind operators) can assess whether an offshore area offers economic potential for offshore hydrogen production. Based on the above, and the consideration of an offshore cost factor of 175%, two views have been developed to indicate a potential infrastructure pathway for the Netherlands' part of the North Sea. These views are largely based on either NvdT – National Management, or on NvdT – Regional Management scenarios of the Infrastructure Outlook 2050 (Gasunie and TenneT, 2019).

Step 4: Market failures and policy

The integration of the electric and molecular system by the development of a hydrogen market, as illustrated by the previous steps, requires governance and timely intervention. This section will distinguish three main reasons why a particular technology, in this case power-to-gas, will not or too slowly become economically attractive to make the desired optimal contribution to the energy transition. The market failures addressed are:
the failure to include relevant aspects from an overall socio-economic perspective in business cases; the risk of being a first-mover for technology positioned in the 'valley-of-death'; and insufficiently clear perspectives on future prices and demand in the absence of a sufficiently developed transparent market for this output. Having discussed the various market failures that may prevent power-to-gas technologies to get off the ground to its socially optimal size, scope, and timing, the logical next question arises what policies and measures can be initiated to address the various types of market failure.

Scenario framework

Determining the volume of hydrogen produced from offshore wind for flexibility purposes is relatively complex as it depends on a number of factors: electricity demand, hydrogen demand, electricity supply etc. The volume of hydrogen produced for flexibility purposes are based on a number of assumptions:

- direct use of electricity in sectors where electrification is feasible is the most preferred option;
- carbon free hydrogen is produced either by converting surpluses of offshore wind energy, or if such production is required by flexibility needs on the power market (e.g. to prevent or overcome e-grid congestion);
- dedicated hydrogen might play a role in case of oversupply of electricity, this is only the case if demand for electrons is foreseen.

The Infrastructure Outlook 2050 or the National and Regional Management models in ETM include an assessment of the economic value of the various flexibility options (Gasunie and TenneT, 2019) (Afman, 2017). Their parameter values have been used as a basis for the hybrid production scenarios in this report. The (NSE-)National Management scenario foresees an immense increase in electric consumption, reaching 1.2EJ in 2050. In the (NSE-) National Management Scenario no oversupply of electricity will arise so that no additional wind capacity is available for dedicated hydrogen production. The role of the offshore wind energy from North Sea in the delivery of electrons is immense, as offshore wind is responsible for 73% of the total electricity supplied. This immense influx of offshore wind leads to a huge need for flexibility. The National Management scenario expects some 61.8 GW of electrolyser to be installed by 2050 offering part of the flexibility needed, namely flexibility for some 3020 hours, or in the order of some 44 EJ of carbon free hydrogen.[5] Due to the high share of offshore wind in the electricity mix by 2050 some 0.32EJ[6] of hydrogen would be produced from offshore wind and given an efficiency of 75% this would require 0.43EJ of electrical input. Hence, the share of offshore wind converted to hydrogen (either onshore or offshore) is in this scenario about 50% (see Table 1).

Conversion to hydrogen	2030	2040	2050	Source/assumption
E-demand	0.49	0.81	1.2	NvdT – National Management for 2050. Expect proportional increase until 2050.
E-supply (solar)	0.05	0.09	0.12	NvdT – National Management for 2050. Expect proportional increase until 2050.
E-supply (wind onshore)	0.06	0.10	0.15	NvdT – National Management for 2050. Expect proportional increase until 2050. Expected load factor of 34%
E-supply (wind offshore	0.19	0.53	0.87	NvdT – National Management for 2050. Expected to load factor of 52%. Expect proportional increase until 2050. 2030 is set to 11.5GW.
E-supply (bio-based/import/fossil based)	0.19	0.09	0.06	Left over after subtraction supply from demand
H2-demand	0.14	0.32	0.57	NvdT – National Management for 2050. Expect proportional increase until 2050
H2-hybrid supply	0.18	0.3	0.44	NvdT – National Management for 2050. Expect proportional increase until 2050
H2-hybrid supply (wind offshore)	0.07	0.2	0.32	Based on share offshore wind in total installed intermittent renewable capacity, which is 73% for 2050.
H2-hybrid supply (other intermittent)	0.11	0.1	0.12	Total H2 hybrid supply minus H2-hybrid supply from wind offshore
E-supply to H2 (offshore wind)	0.09	0.26	0.43	Input from hybrid supply from offshore wind divided by efficiency of 75%
Share wind to be converted	49%	49%	49%	E-supply for H2 (from offshore wind) divided by total E-supply from offshore wind.

Table 1: Model input hybrid hydrogen in 2050 in NSE - National Management

[5] https://pro.energytransitionmodel.com/scenario/overview/introduction/how-does-the-energy-transition-model-work

6 Some 73%, which is based on the share of offshore wind in the total share of intermittent resources.

Table 2 provides an overview of the main parameters used to determine the share of offshore wind used for hybrid hydrogen production in the (NSE-) Regional Management scenario. The (NSE-) Regional Management scenario foresees an increase in electric consumption that is significantly lower than in the NSE-National Management scenario, i.e. reaching 0.22EJ in 2050. In the NSE-Regional Management scenario immense oversupply of carbon free electricity production will arise: total supply will rise to 0.9EJ by 2020, whereas demand increases to only 0.22EJ. This provides opportunities for dedicated hydrogen production, as hydrogen demand is expected to rise to 0.42EJ: some 15GW of the installed wind capacity in 2050 will be available for dedicated hydrogen production; the other 11.5GW capacity available will suffice to satisfy future electricity demand and the need for flexibility. The role of offshore wind energy from the North Sea in delivering power still is 48% of total electricity supplied. The immense influx of offshore wind leads to a need for flexibility. The expectation is that some 0.14 EJ of hydrogen will be produced to provide flexibility to the energy system. The share of offshore wind converted to hydrogen by 2050 (either onshore or offshore) is 43% (0.18/0.43).

Conversion to hydrogen	2030	2040	2050	Source/assumption
E-demand	0.06	0.11	0.22	NvdT – Regional Management for 2050. Expect proportional increase until 2050.
E-supply (solar)	0.13	0.21	0.3	NvdT – Regional Management for 2050. Expect proportional increase until 2050.
E-supply (wind onshore)	0.07	0.12	0.17	NvdT – Regional Management for 2050. Expect proportional increase until 2050. Expected load factor of 34%
E-supply (wind offshore	0.19	0.31	0.43	NvdT – Regional Management for 2050. Expected to load factor of 52%. Expect proportional increase until 2050. 2030 is set to 11.5GW.
E-supply (bio-based/import/fossil based)	0	0	0	Left over after subtraction supply from demand
H2-demand	0.12	0.27	0.42	NvdT – Regional Management for 2050 for 2050. Expect proportional increase until 2050
H2-supply for flexibility	0.13	0.21	0.29	NvdT – Regional Management for 2050 Expect proportional increase until 2050
H2-supply (wind offshore)	0.065	0.10	0.14	Based on share offshore wind in total installed intermittent renewable capacity, which is 48% for 2050.
H2-supply (other intermittent)	0.065	0.11	0.15	Total H2 hybrid supply minus H2-hybrid supply from wind offshore
E-supply to H2 (offshore wind)	0.08	0.13	0.18	Input from hybrid supply from offshore wind divided by efficiency of 75%
Share wind to be converted	**43%**	**43%**	**43%**	**E-supply for H2 (from offshore wind) divided by total E-supply**

Table 2: Model input hybrid hydrogen in 2050 in NSE – Regional Management

As indicated before, dedicated hydrogen might play a role in case of oversupply of electricity, this is only the case if demand for electrons is foreseen. The hydrogen volumes from dedicated production are completely determined by the available space on the Dutch continental shelf for the installation of wind farms (assuming that space is used as efficiently as possible). The upper limit of dedicated carbon free hydrogen production is obviously either set by the national demand for carbon free hydrogen or by the offshore space restrictions. The PBL-scenarios are used to make first guestimates about the North Sea potential for dedicated hydrogen production. These scenarios can be viewed as supportive, but not similar, to the National Management and Regional Management ones. The fact that the offshore capacity in the PBL scenarios is higher than in the National Management and Regional Management scenarios highlights a higher potential of dedicated carbon free hydrogen production. To illustrate, the PBL Sustainable Together scenario assumes 60GW of offshore wind capacity to be installed by 2050, whereas the National Management scenario assumes 53GW. The difference, 7 GW, has been assumed in this study to be used for dedicated hydrogen production. The (NSE-) Regional Management scenario demonstrates, for instance, a need for dedicated offshore wind parks in the order of 0.18EJ to ensure that complete national hydrogen demand can be satisfied by national production. In some simulated cases the annual hydrogen demand cannot be satisfied by the combined production of hybrid and dedicated hydrogen. For those cases it was assumed that demand is fulfilled by either domestic low carbon hydrogen production, or by hydrogen imports. The next section will describe the scenarios used as an input for the offshore system calculations more specifically.

Scenario descriptions

Figure 2 shows the scenarios that are considered for this report. The scenarios have all a significantly different design of the energy system which will result in different optimisations of the offshore infrastructure. Yet, each scenario achieves the 95% emission reduction target for 2050. The scenarios highlighted in light blue depict alternatives to the NSE scenarios based on (WerkgroepH2, 2019), and (Matthijsen, 2018). The difference between the two relates to hydrogen demand and offshore wind capacities installed. For the energy system design (e.g. the degree of electrification) the NvdT scenarios (Gasunie and TenneT, 2019) are used. The role of dedicated carbon free hydrogen is based on an internal analysis (see page 18).

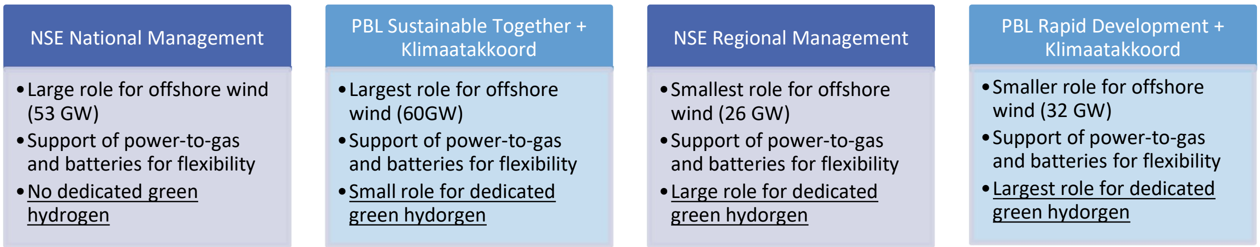

Figure 2: Overview of considered scenarios for 95% CO2 reduction in 2050

National Management – base case I

In this case the national government takes the lead in the energy transition by putting a key role on centralised wind power production and a high level of electrification of the final demand. This strategy results in a total installed wind capacity of 53 GW in 2050, with an intermediate step of 11.5 GW in 2030. Due to this significant increase in wind capacity by 2050, by that time a larger conversion capacity is needed to balance offshore produced intermittent electricity. The calculations show that because in this case the share of offshore wind in the total intermittent electricity supply in 2050 will grow to about 73%, a total electrolyser capacity of 61.8 GW needs to be installed to offer the required flexibility (for some 3020 hours a year) for the complete, on- and offshore power system.[7] This capacity delivers 0.44 EJ[8] of hybrid hydrogen per annum. Based on the same about 73% one can conclude that in 2050 some 0.32 EJ of hydrogen can be attributed to offshore wind. The remaining, about 0.12 EJ, hydrogen produced is needed for balancing other intermittent electricity resources. In this case the hybrid hydrogen production turns out to be sufficient to cover the Dutch demand for hydrogen in 2030 and 2040, and to do so to a large extent in 2050 (see also Figure 3). Some low carbon hydrogen (i.e. hydrogen from natural gas in combination with CCS) and/or hydrogen import is needed by that time to cover the remaining national hydrogen demand. The 53GW installed wind capacity mentioned in the central roll-out strategy is fully needed for fulfilling national electricity demand. So, in the NSE national management scenario no additional space is assumed to be available for wind parks producing dedicated hydrogen.

[7] Energy Transition Model – national management scenario used as input for the Infrastructure Outlook 2050. (https://pro.energytransitionmodel.com/scenario/overview/introduction/how-does-the-energy-transition-model-work)
[8] Equivalent to some 3 Mt of hydrogen (HHV based).

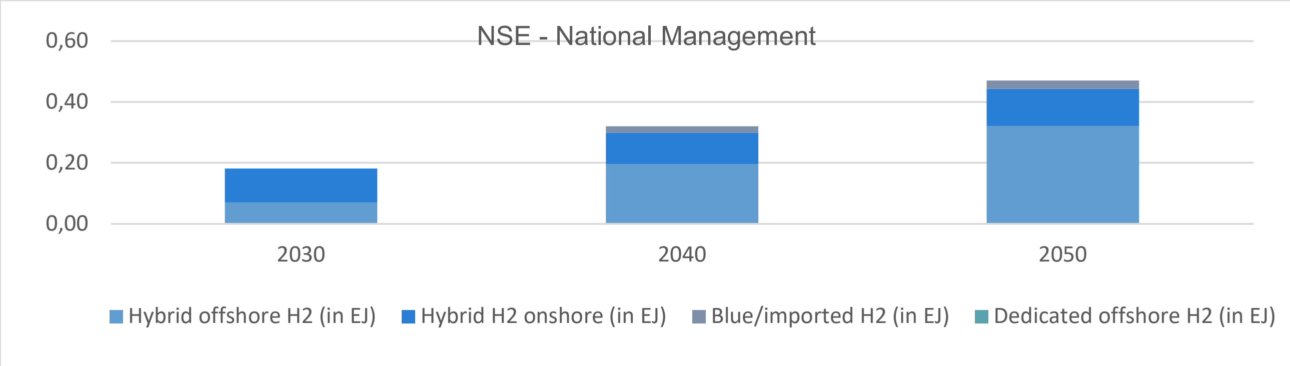

Figure 3: Potential of hydrogen supply in NSE - National Management scenario. Hydrogen demand in this scenario in 2030, 2040 and 2050 is 0.14EJ, 0.32EJ and 0.47EJ, respectively

Regional Management – base case II

In this case the municipal governments take the lead in the energy transition by emphasising decentralised power production and a lower level of electrification of the final demand. The role of the North Sea as the future energy provider in this scenario is much smaller than in the preceding case, resulting in a total installed wind capacity of just 26 GW in 2050 but with the same intermediate step of 11.5 GW in 2030. A total of 74.6 GW of electrolyser capacity is installed to offer the required flexibility for the on- and offshore power system.[9] The installed capacity delivers 0.29 EJ of hydrogen per annum. Based on the share of offshore electricity in the total amount of intermittent electricity production (about 48% in 2050), some 0.14 EJ of hydrogen per annum can be linked to offshore wind, and the remaining about 0.15 EJ to other intermittent electricity sources. The combined supply of the hybrid hydrogen production is sufficient to cover the Dutch demand for hydrogen in 2030, and is almost sufficient in 2040 (see also Figure 4). Due to the overcapacity of intermittent power production in 2050 (total power production of 0.9 EJ in contrast to 0.22 EJ of demand), there is potentially a large role for dedicated offshore hydrogen production. Figure 4 highlights that dedicated production from offshore wind may be sufficient to generate supply needed to cover the overall national demand for hydrogen, as assumed in the NSE - Regional Management scenario.

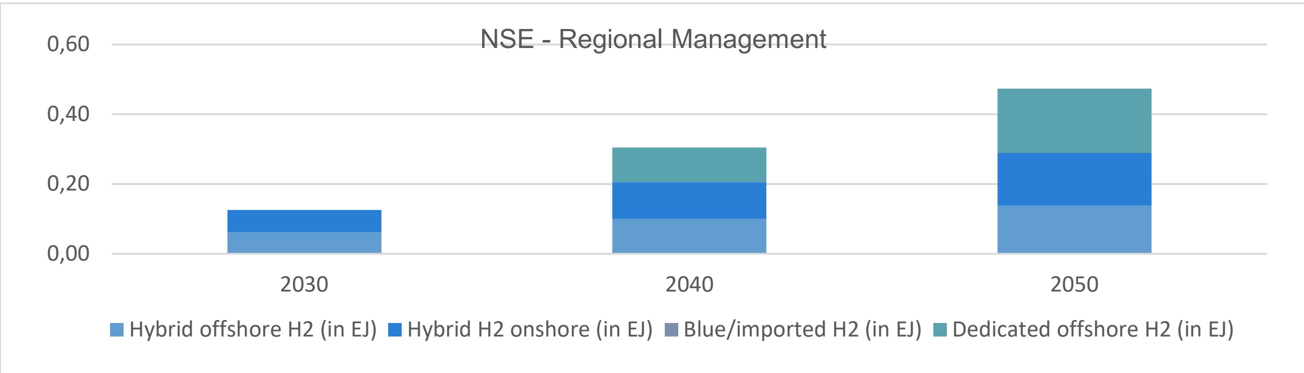

Figure 4: Potential of hydrogen production in NSE - Regional Management case. Hydrogen demand in this scenario in 2030,2040 and 2050 is 0.12EJ, 0.27EJ and 0.42EJ, respectively

An alternative to the National Management scenario

Recently new hydrogen demand scenarios have been developed by the working group supporting the Climate Agreement. Although their medium scenario is similar to that of NSE - National Management,

[9] Energy Transition Model – national management scenario used as input for the Infrastructure Outlook 2050. (https://pro.energytransitionmodel.com/scenario/overview/introduction/how-does-the-energy-transition-model-work

an alternative high demand scenario is also presented. In this scenario, again the national government is expected to take the lead in the energy transition with an emphasis on centralised production of wind energy and a high level of electrification of final demand (11.5 GW in 2030, and 60 GW in 2050). The difference in installed wind capacity of 7 GW (60 versus 53 GW) is attributed to dedicated hydrogen production. Due to the assumed high degree of electrification of the final demand sectors (such as the built environment), seasonal flexibility mechanisms such as power-to-gas are required. A total of 61.8 GW of electrolyser capacity is installed to offer the required flexibility for the on- and offshore power system. The installed capacity delivers a total of 0.44 EJ of hydrogen per annum. Based on the share of offshore electricity in the total amount of intermittent electricity production (about 73% in 2050), some 0.32 EJ of hydrogen per annum could be attributed to offshore wind and the remaining, some 0.12 EJ, to the other intermittent electricity resources. The combined supply based on the hybrid and dedicated hydrogen production is insufficient to cover the Dutch demand for hydrogen, as assumed by the hydrogen working group in the high-demand scenario, in 2030, 2040, and 2050 (see also Figure 5). National low carbon hydrogen production (in combination with CCUS) or imports of hydrogen from other regions is required to satisfy this high level of hydrogen demand.

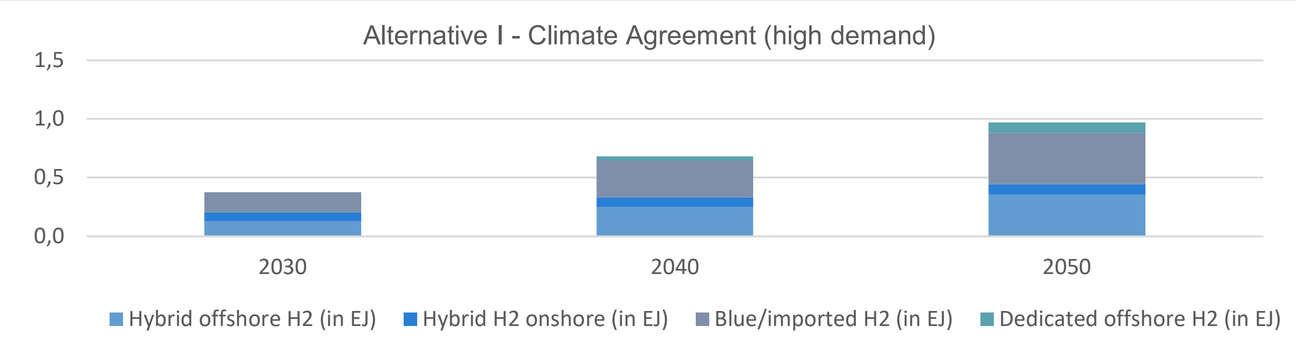

Figure 5: Potential of hydrogen production as by the hydrogen working group for the Climate Agreement (high) combined with PBL – Sustainable Together. Hydrogen demand in this scenario is 0.30EJ, 0.60EJ and 0.88EJ in 2030, 2040 and 2050, respectively

An alternative to Regional Management

Also, for the NSE - Regional Management scenario an alternative has been established. This is based on the PBL scenario 'Rapid Development' and the high-demand scenario of the hydrogen working group (within the Climate Agreement). The municipal governments are still expected to take the lead in the energy transition with an emphasis on decentralised power production and a lower level of electrification of final demand. The role of the North Sea as the future energy provider in this scenario is larger, resulting in a total installed wind capacity of 11.5 GW in 2030 and 32 GW in 2050. The difference in installed capacity (32 GW in 2050 compared to 26 GW of the similar regional management scenario) is expected to be attributed to dedicated hydrogen production. A total of 74.6 GW of electrolyser capacity is installed to offer the required flexibility for the on- and offshore power system. The installed capacity delivers a total of 0.29 EJ of hydrogen per annum. Based on the share of offshore electricity in the total amount of intermittent electricity production (about 48% in 2050), some 0.14 EJ of hydrogen per annum could be attributed to offshore wind and the remaining, some 0.15 EJ, to other intermittent electricity sources. In this scenario, results show that the combined supply of the hybrid hydrogen production is insufficient to cover the Dutch demand for hydrogen in 2030, 2040 and 2050 (see also Figure 6). Even with a growing role for dedicated hydrogen production from 2040 onwards, low carbon hydrogen production (in combination with CCUS) will have to play a significant role in satisfying overall demand for hydrogen in the Netherlands, as assumed in the hydrogen working group's high-demand scenario (WerkgroepH2, 2019).

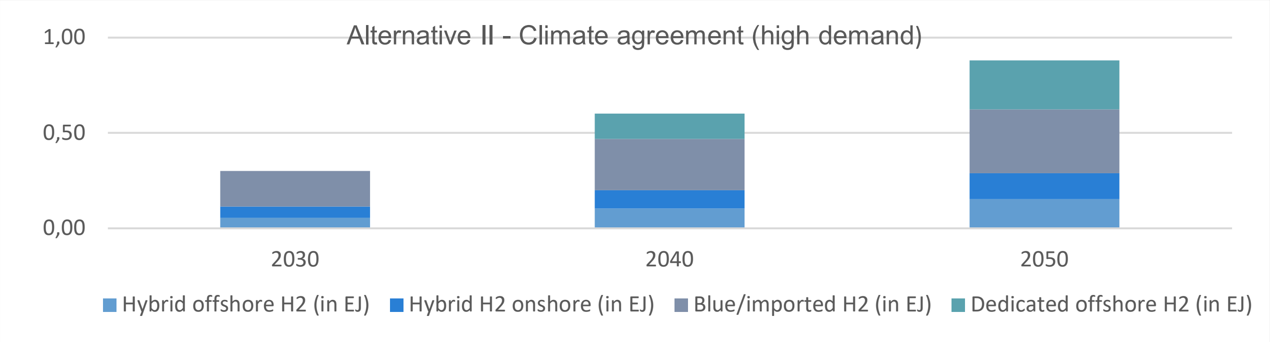

Figure 6: Potential of hydrogen supply as projected by the hydrogen working group for the Climate Agreement (high) combined with PBL – Rapid Development. Hydrogen demand in this scenario is 0.30EJ, 0.60EJ and 0.88EJ in 2030, 2040 and 2050,respectively.

The above section has described the scenarios that are considered for this report. In the next two sub-paragraphs more attention is given to the rationale behind the assumptions for the demand and supply of hydrogen

Hydrogen demand

Distribution over sectors

How the hydrogen economy will evolve is uncertain since many aspects of the demand and supply chain as well as the business models of hydrogen producers are not clear yet. However, the Dutch Climate Agreement includes an analysis on the potential hydrogen development until 2050. The outcomes of this agreement are compared with the expectations formulated in the National Management and Regional Management scenarios (see Table 3). All management scenarios have in common that hydrogen demand is going to increase from 0.4 EJ to 0.8 EJ in 2050. This demand will to a large extent come from the industrial sector, with more than 50% of total demand coming from industrial energy use and industrial feedstock. The National Management and Regional Management scenarios differ regarding the role of hydrogen in the built environment and for electricity generation. The reason for this is probably the high degree of electrification that forms the backbone of the National Management scenario, whereas the Regional Management scenario assumes a larger role for biomass as an energy input to the built environment. The medium scenario of the hydrogen working group of the Climate Agreement is broadly in line with the NSE - National Management and NSE - Regional Management outcomes. The high scenario of the hydrogen working group, which is used in both alternative roadmaps, assumes a much larger role for hydrogen in the future, especially in electricity production and mobility, which results in twice the demand of the medium scenario (see Table 3).

Values in EJ/Y	NSE - National Management	NSE - Regional Management	High (hydrogen working group)
Mobility	0.16	0.11	0.32
Build Environment	0.32	0.03	0.24
Electricity	0.02	0.27	0.5
Industrial feedstock	0.29	0.29	0.39
Agriculture	-	-	0.01
Industrial energy use	0.14	0.14	0.3
Total	0.93	0.84	1.76

Table 3: Potential hydrogen demand in 2050 according to various sources [in EJ].
The following running hours have been assumed for the respective sectors: mobility - 8760 hours/y, built environment - 2000 hours/y, electricity – 6000 hours/y, industrial feedstock 8760 hours/y, agriculture – 5000 hours/y, and industrial energy use – 8000 hours/y. These running hours have been taken from the hydrogen working group data. The NSE scenarios do not take the agricultural sector as a potential user into account.

Distribution over regions

A projection of the regional distribution of hydrogen demand has been generated within the hydrogen working group for the Climate Agreement. This regional distribution for 2050 is based on the following assumptions:

- Hydrogen for :built environment and mobility: per capita and total inhabitants per province
- Hydrogen for electricity production: 50% Eemshaven, 50% Rotterdam
- Hydrogen for industrial feedstock: distribution consistent with current situation (37% Zeeuws-Vlaanderen, 22% Maasvlakte, 18% Zuid Limburg, 13% Eemshaven, 10% IJmond)
- Hydrogen for agricultural use: just in the Maasvlakte region (Westland)
- Hydrogen for industrial heat: distribution according to Blueterra study (48% Maasvlakte, 26% Zeeuws-Vlaanderen, 15% Zuid-Limburg, 10% IJmond, 1% Eemshaven)

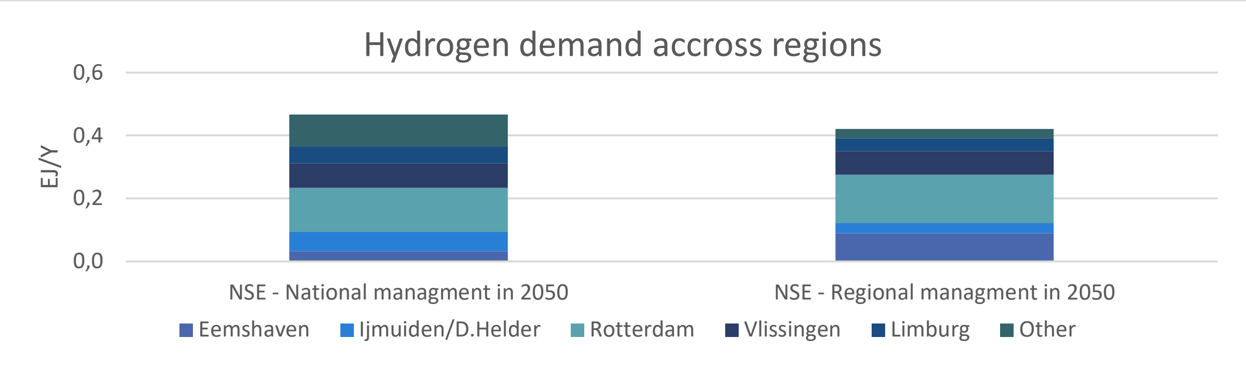

Figure **7** provides an example of the regional demand distribution within the NSE scenarios for the year 2050. Sectorial differences in hydrogen demand between the two NSE scenarios also result in some differences in regional hydrogen uptake. In both scenarios, about a third of the total hydrogen demand comes from the Rotterdam region. The hydrogen demand in the Eemshaven and IJmuiden region varies between both scenarios. This can be explained by the difference in the share of hydrogen for electricity supply, which is relatively large in the NSE - Regional Management scenario compared to the NSE – National Management scenario. Currently, a large share of electricity is produced in the Eemshaven, and it is expected that part of the installations in that location will be modified to support the production of hydrogen as a fuel. The expectation is that an onshore hydrogen network will be established by 2030, and that the location of landing therefore is of limited importance for the scenario specifications[10].

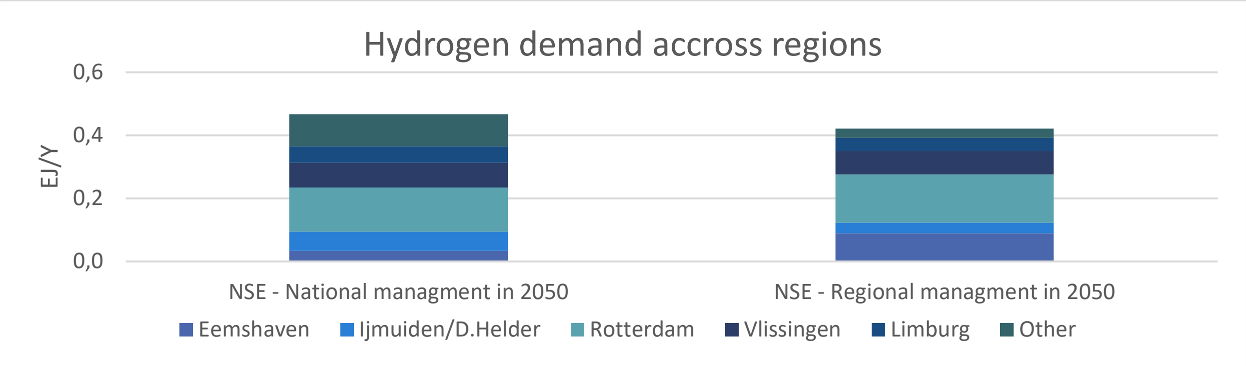

Figure 7: Overview of hydrogen demand across various regions

[10] This expectation is validated by the NSE – consortia members during one of the workshops

Hydrogen supply

The degree of electrification

The degree of electrification of various sectors in the Netherlands has a strong relationship with: the installed capacity of renewable energy (incl. offshore wind); the need for additional infrastructure investments; as well as the need for flexibility and storage. The two selected scenarios differ with respect to the degree of electrification of the industry and households (Figure 8). The National Management scenario assumes an increase in electric demand by 2050 (as compared to 2015) to about 1.1 EJ/a, or a growth of 2000%. This increase is among others a result of the assumed high degree of electrification in the industry sector. The Regional Management scenario assumes a lower degree of electrification, although the increase is still a remarkable 400% (compared to 2015).The lower demand for electric input relates to smaller penetration rates of intermittent electricity resources, especially for offshore wind (see also Table 4). This explains to a large extent the high penetration of offshore wind capacity in the NSE - National Management scenario. The increase in intermittent electric energy supply requires additional investment in electric infrastructure, e.g. in the case of National Management some 53 GW of offshore electric infrastructure would be required. On top of that the low voltage and medium voltage grid capacities should be extended by some 30%, or in absolute terms by 5.6 GW and 7.4 GW, respectively.

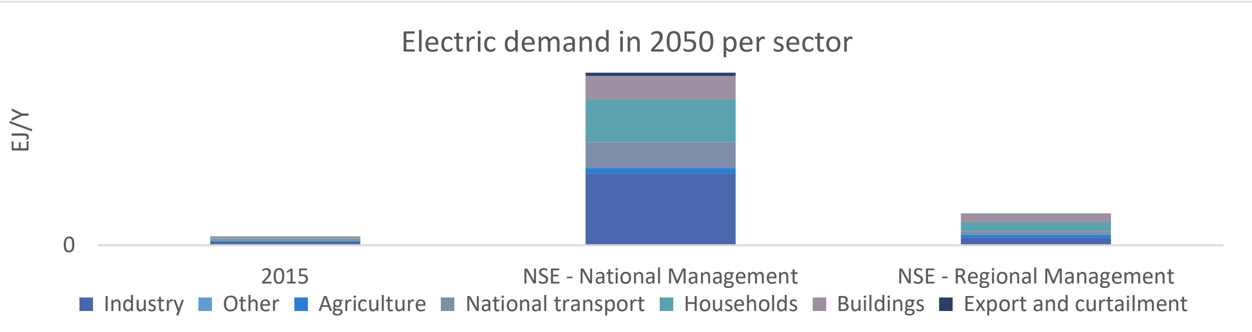

Figure 8: Electric demand in 2050 per sector

	National Management [EJ]	Regional Management [EJ]	Alternative I [EJ]	Alternative II[EJ]
Electric demand	1.2	0.218	1.2	0.218
Total intermittent electric supply	1.2	0.9	1.2	0.9
Electric supply by solar panels	0.12	0.3	0.1	0.3
Electric supply by onshore wind	0.15	0.17	0.15	0.17
Electric supply by offshore wind	0.87	0.43	0.98	0.52

Table 4: Overview of intermittent electricity production in 2050. Data has been gathered from the ETM model NSE - National Management and NSE - Regional Management. The wind capacities for the alternative scenarios are taken from the PBL III: Rapid Development

Electric supply by offshore wind

Four scenarios with respect to offshore wind development are considered (Table 5). The base case scenarios are based on installed capacities as mentioned in the NSE scenarios. Moreover, the PBL scenarios have been used as alternative scenarios and have been very helpful in pointing out potential locations of future wind parks. Until 2030 the rollout of offshore wind and likely locations of interconnection points onshore is reasonably well-known.[11] However, for the period thereafter for likely wind farm locations one has to typically rely on assumptions which have been based on indicative scenarios from the PBL reports mentioned. The rollout of the NSE - National Management scenario is based on the layout of alternative I – National Management. The rollout of the NSE - Regional Management scenario is based on the layout of alternative II - Rapid Development. Figure 9 illustrates the expected future rollout of offshore wind capacities in the PBL scenarios. Blue highlights the known location of the 10.6 GW until 2030 (900 MW has not been allocated yet); pink highlights the potential development between 2030 and 2040, whereas green highlights the development after 2040. The allocation of blue and green areas is based on the assumption that areas located further from shore will be developed at a later stage.

	2030	2040	2050
NSE - National Management	11.5 GW	32.25 GW	53 GW
NSE - Regional Management	11.5 GW	18.75 GW	26 GW
Alternative I – Sustainable Together	11.5 GW	35.75 GW	60GW
Alternative II – Rapid Development	11.5 GW	21.75 GW	32 GW

Table 5: Scenarios for offshore wind development 2030-2050

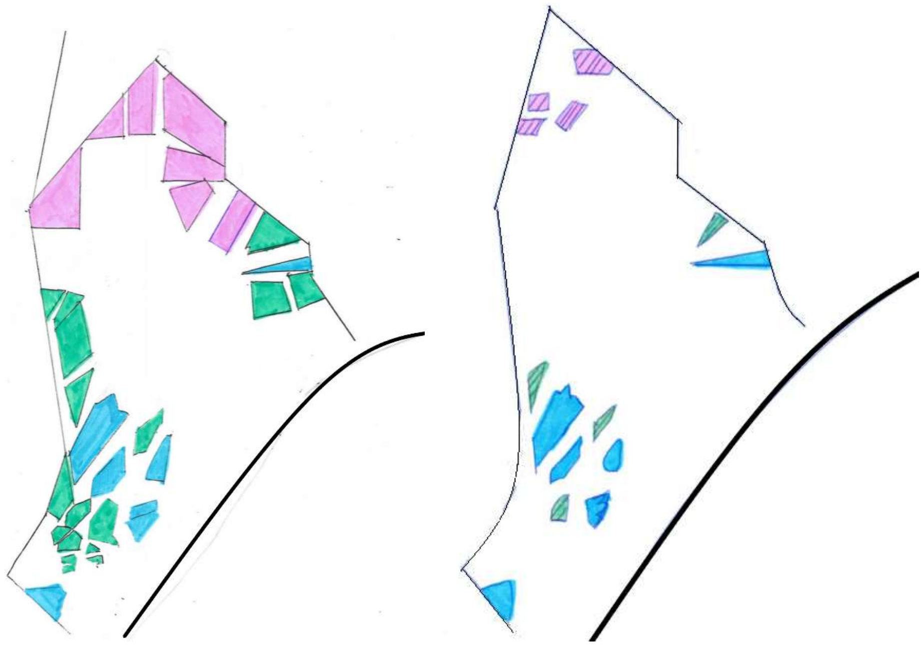

Figure 9: On the left the PBL-scenario sustainable together highlights a potential roll out of offshore wind capacity after 2030 towards 60 GW. On the right the PBL-scenario rapid development highlights a potential roll out of offshore wind after 2030 towards 32 GW.

Hydrogen supply

For assessing the role of the various flexibility options we refer to the Infrastructure Outlook 2050 report mentioned earlier as well as to the National and Regional Management models in ETM (Gasunie and TenneT, 2019) (Afman, 2017). Table 6 gives an overview of the flexibility provided by conversion to hydrogen as mentioned in the National Management and Regional Management scenarios. Their numbers are used as a basis for the hybrid production scenarios. To illustrate, the National

11 https://www.rvo.nl/sites/default/files/2019/04/kamerbrief-over-de-voortgang-uitvoering-routekaart-windenergie-op-zee-2030.pdf

Management scenario expects some 61.8 GW of electrolyser capacity to be installed by 2050 to offer flexibility for 3020 hours to the national electricity grid.[12] Some of this flexibility and thus conversion need, can be attributed to the offshore systems. The national management scenario indicates the need of 0.44 EJ[13] of hybrid hydrogen per annum to provide sufficient balance to the energy system. Based on the share of offshore wind production in the total amount of intermittent electricity production (about 73% in 2050), some 0.32 EJ of hydrogen production in 2050 can be attributed to offshore wind. The remaining, about 0.12 EJ, can be attributed to other intermittent electricity production sources. Due to the significantly larger role of offshore wind capacity by 2050 in the National Management scenario, in this scenario obviously the role of offshore in determining flexibility needs is larger. The share of offshore wind in the total intermittent electricity supply of the Regional Management scenario is just 48% so that in this scenario the volume of hydrogen produced for flexibility reasons is much smaller.

Apart from hybrid hydrogen production, dedicated hydrogen production has been considered. In the latter case the installation of wind capacity is constrained by the availability of space on the Dutch continental shelf. That space obviously should be used as efficiently as possible. This implies, that if national electricity demand is not (yet) fulfilled, additional wind energy will be installed and consequently hybrid conversion to offer the flexibility required to balance the system. However, if national electricity demand is fulfilled, the offshore space may be used for wind parks producing dedicated hydrogen. So, the upper limit of dedicated hydrogen production is either set by the national demand for hydrogen or by the restriction regarding the available space for offshore wind production. The PBL-scenarios are used to make a first guestimate on the North Sea potential for dedicated hydrogen production. These scenarios are supportive, but also slightly alternative to the National Management and Regional Management ones. The larger offshore capacity in the PBL scenarios than in the National Management and Regional Management scenarios highlights its larger potential for dedicated carbon free hydrogen production. To illustrate, PBL Sustainable Together assumes 60GW of offshore wind capacity to be installed by 2050, whereas the National Management 53GW. In our analysis, the difference, 7 GW, is used for dedicated hydrogen production. In some cases, the annual hydrogen demand is not satisfied by the combined production of hybrid and dedicated hydrogen. In those situations, the demand is expected to be satisfied by either domestic low carbon hydrogen production, or by imports.

Conversion to hydrogen	Installed capacity electrolysers (MW)	Annual energy output (PJ)[14]	Total Annual electric output (PJ)	Full load hours (hr)	Annual energy output from offshore wind (EJ)
NSE - National Management & Alternative I [15]	61800	443	672	3019.8	0.34
NSE - Regional Management & Alternative II[16]	74590	289	438	1629.9	0.14

Table 6: Hybrid hydrogen production in 2050.
The hybrid production of carbon free hydrogen from offshore wind is calculated in proportion to the contribution of offshore wind in the total intermittent electric production.

The various scenarios clearly show as an overall picture that it is likely that imports of hydrogen or the domestic production (or imports) of low carbon hydrogen becomes necessary to fulfil the demand for hydrogen in the Netherlands 'energy and feedstock system by 2050 (Table 7). This becomes even

12 https://pro.energytransitionmodel.com/scenario/overview/introduction/how-does-the-energy-transition-model-work
13 Equivalent to some 3 Mt of hydrogen (HHV based).
14 Equivalent to some 3 Mt of hydrogen (HHV based).
15 Retrieved from: https://pro.energytransitionmodel.com/scenario/overview/introduction/how-does-the-energy-transition-model-work
16 Retrieved from: https://pro.energytransitionmodel.com/scenario/overview/introduction/how-does-the-energy-transition-model-work

clearer in the alternative cases[17]. If a hydrogen economy would be realised at the scale of the high-case scenario as depicted by the hydrogen working group (Climate Agreement), there is a large discrepancy between the volume of carbon free hydrogen that could be domestically produced, and hydrogen demand. Regarding the volumes of CO_2 to be captured and stored (or used) related to low carbon hydrogen production, the reader is referred to D1.5.

Conversion to hydrogen	Carbon free hybrid hydrogen from offshore wind	Carbon free dedicated hydrogen from offshore wind	Carbon free hybrid hydrogen from other intermittent resources	Low carbon hydrogen and/or import
NSE - National Management	0.32	0	0.12	0.03
NSE - Regional Management	0.14	0.18	0.15	0
Alternative I	0.32	0.09	0.12	0.44
Alternative II	0.14	0.26	0.15	0.33

Table 7: Hydrogen mixes in the various scenarios for 2050

[17] Blue hydrogen production (in combination with CCS) and/or hydrogen imports might not be required in the National management scenario.

Offshore infrastructure

As mentioned in the previous paragraphs, the Dutch part of the North Sea can contribute significantly to the development of a hydrogen system via hybrid or dedicated hydrogen production. The first part of this chapter provides an overview of the system boundaries for both the hybrid and dedicated systems, whereas the second part outlines the offshore the various system element: the offshore substructures (either islands or (existing) platforms); and the transmission infrastructure (electric or gaseous).

System boundaries hydrogen production

Hybrid hydrogen production

In the hybrid scenario part of the electricity from offshore wind is delivered directly to end-users via the transmission net and part of the electricity is converted into hydrogen before it is transported to the end-user. The typical benefits of this option are that one has some flexibility to shift from one option to the other so that benefits from hydrogen-power prices can be optimised as well as premiums from generating flexibility to the electricity system. In hybrid scenarios therefore only part of offshore wind energy is converted, The NSE – National Management scenario and the NSE – Regional Management scenario assume, for instance, conversion of only 49% and 43% respectively of the installed wind capacity (see also Table 1 and Table 2). The location of the conversion installation in hybrid scenarios strongly depends on the costs and benefits of the electric and molecular transmission (and distribution) systems. Figure 10 highlights the main infrastructure components of either an onshore or an offshore hybrid production system.

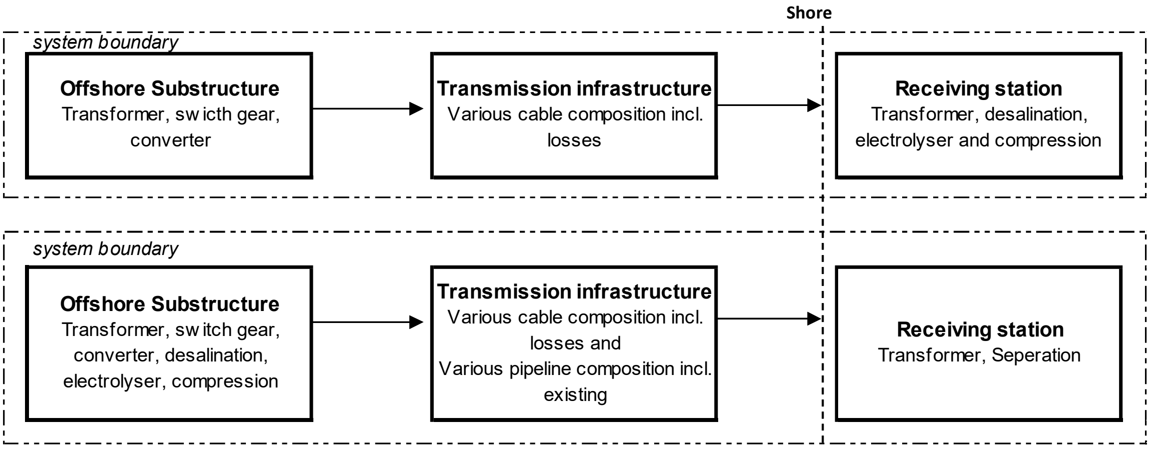

Figure 10: System elements onshore (above) and offshore conversion in hybrid production scenario

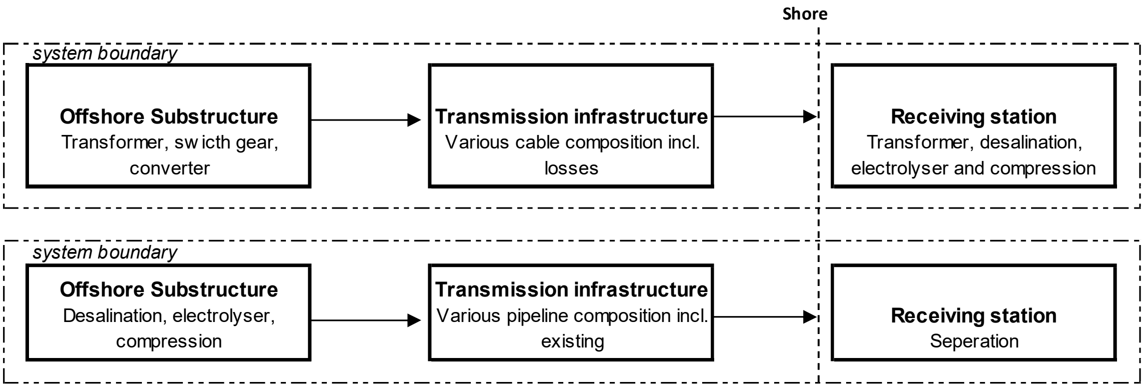

Figure 11: System elements onshore (above) and offshore conversion in dedicated production scenario

Dedicated hydrogen production

In some scenarios the Dutch continental shelf of the North Sea offers potential for dedicated hydrogen production: all wind power will be converted into hydrogen, so that there is no longer a need to connect the offshore wind farm to shore with an electricity grid connection. Especially if such an infrastructure is not available and costly to install, not being forced to make such investment but instead using existing gas infrastructure will constitute potentially a considerable societal benefit. Even then there is the option to either convert the wind energy into hydrogen offshore, or onshore. Our scenarios, both the NSE – National Management and NSE – Regional Management scenario, assume such dedicated hydrogen production to amount between 0 and 0.17EJ/y in 2050. Obviously, again, the location of the conversion installation highly depends on the costs and benefits of each location as well as of the infrastructure costs related to transport and possibly storage. Figure 11 highlights the main infrastructure components of either an onshore or offshore dedicated production system.

Infrastructure requirements

The offshore infrastructure consists apart from the conversion equipment (desalination, electrolyser, compression etc.) of two common elements: a substructure (island or platform) that host the electric and/or molecular system; and a transmission infrastructure either electric or gaseous. The various design options for the structure and the transmission network are discussed here in more detail. The assumptions regarding the conversion process are discussed on page 28.

Substructure for the conversion process

The production of hydrogen on an offshore location requires a substructure, either platform or island, that will be able to host the required multitude of functionalities. It should at least be able to host the power-to-hydrogen conversion installation (converter station, desalination unit, electrolyser, balance of plant and compression), a helicopter platform, a cable landing zone and accommodation. For a survey on the sizing considerations and thus costs of various types of islands, the reader is referred to D 3.8 and D3.2. Its main conclusion is that the space needed for an offshore power-to-hydrogen conversion installation (converter station, desalination unit, the electrolyser, the balance of plant, the compression, etc.) and the additional accommodation commonly needed typically requires some 10.000 m^2 of surface per 100 MW of electrolyser capacity installed. Although, the sizing of conversion technologies follows a modular approach, the economics of scale of constructing (sandy) energy islands are considerable. For instance, substructure costs of a 2GW island with 30% of conversion are about 600k euro per MW, whereas similar case costs for a 20GW island amount to some 100k euro per MW only. The substructure costs for platform follow, unlike energy island, a linear profile. Platforms can however be important stepping stones in the development of offshore hydrogen production.

New platform infrastructure

The costs of new platforms has been analysed by (DNVGL, Power-to-Hydrogen Ijmuiden Ver. Final report for TenneT and Gaunie, 2018, p. 31), specifying the topside construction, pile mass construction, and the substructure costs. For installation they assumed a cost percentage of 15% for construction and fabrication. A disclaimer has been pointed at for these numbers:” The uncertainty in the mass estimation is +25%/-30%. As the maximum capacity available from other projects is 900 MW, the uncertainty for the 2 GW P2H2 is quite high” (DNV GL, 2018). They estimated that, given a power input of 100 MW, a volume of 19,355 m^3`is required. Assuming a platform height of 15 m, and 4 layers, a total surface of 5,150 m^2 per layer should therefore be sufficient to collectively host a 100 MW electrolyser package. However, some detailed engineering (see D3.8) suggests that rather some 10.000 m^2 of surface per 100 MW of electrolyser capacity would be required. This will lead to a topside volume of 291 m^3/MW instead of 193.55 m^3/MW as stated in the DNV GL report, implying almost a factor 2 increase in surface requirement, and therefore in the estimated mass of the supporting steelwork, grating area, estimated coating area, pile mass and structure. Moreover, in line with (DNVGL, Power-to-Hydrogen Ijmuiden Ver. Final report for TenneT and Gaunie, 2018), an additional platform was considered necessary when total conversion capacity exceeds 2 GW. Page 53 gives an overview on the assumptions and the approach taken to come to these costs. On the basis of these assumptions, a 100 MW dedicated new platform for power-to-hydrogen costs about 30 million euro (see Figure 12).

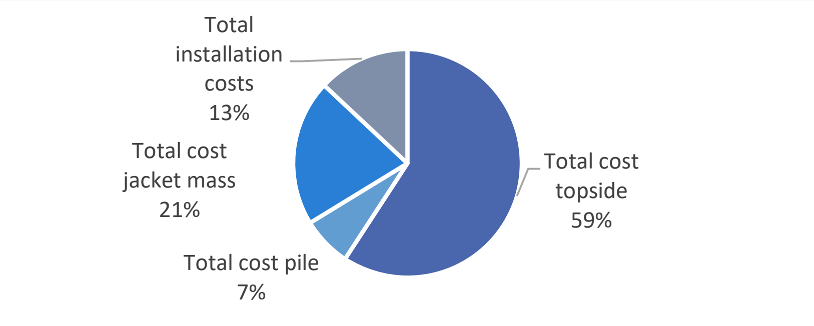

Figure 12: Distribution of capital investment cost components of a 100 MW power-to-hydrogen platform

Existing platform infrastructure

The economic lifetime of existing platforms is about 30 years. However, the economic and technical lifetimes are not the same. An extension of the jacket lifetime can be achieved via diving inspections that may prove that there are no severe accumulated damages, or by studying measured wind/wave data to show that the conditions it has been subjected to were less severe than those it was designed for. The potential for re-use of existing platforms depends on a number of factors. First, the timing at which these platforms become available should align with wind developments in the same regions, and second, the size of the platforms: production platforms have a greater potential since they have a greater carrying capacity. Third, platforms may be claimed for other system integration solutions such as CCS (D 1.3 provides more insight in the role of existing platform infrastructures for this). The rollout of an offshore CO_2 transport network can simultaneously both enable and slow down the development of a hydrogen network. At the one hand, they may encounter time-overlap in their activities, especially for platforms located in promising wind areas, such as K14 and K18. On the other hand, synergies exist between both processes and may therefore lead to higher system value as highlighted in NSE 2. Another significant factor when considering offshore electrolysis on existing platforms is a platform's capacity to host a certain capacity of electrolysers. The section below provides an indication of potential suitable offshore substructures for hydrogen conversion given their mass capacity and their size limitations. Data and insights on the potential carrying capacity of existing jackets and on their topside mass have been derived from (Ospar, 2015). It is important to note that in this study it has been assumed that for installing electrolysis capacity the topside of the platform will have to be removed and replaced by an onshore dedicated designed topside (Jepma & Van Schot, 2017).

Supporting steelwork – mass limitations
In the DNVGL study mentioned a jacket mass of 35,231 tonnes was estimated to be needed for enable installing a 2 GW hydrogen conversion capacity (DNVGL, Power-to-Hydrogen Ijmuiden Ver. Final report for TenneT and Gaunie, 2018, p. 31). By applying the correction factor of 2 mentioned before the estimated jacket mass of the supporting topside for 2GW installed capacity turned out to be some 70,462 tonnes. Based on this figure, a shortlist of relevant platforms is listed (Table 8). Note that the potential conversion capacities of the shortlisted platforms are only based on the carrying capacity of the existing jacket. There may be other reasons, for instance limitations to topside volumes, why the carrying capacity of the existing platforms is reduced drastically. Regarding costs of refurbishing platforms, a previous study (Jepma & Van Schot, 2017) suggests to only replace the topside of the platform. If an existing jacket and pile would be reused and the topside redesigned and installed, it would cost about 200k euro per MW installed electrolyser capacity. An additional 15% increase in costs is considered for the installation of the new topside. In case of re-use, one could save some 21% on the jacket costs of the platform (for further details, see **Error! Reference source not found.**page 53).

	<50 MW	50MW> <100MW	100MW> <200MW	>200MW
Existing platforms (Ospar, 2015)	A12, AME, AWG, F15, G14, G16, K17, L02, L04, L06, L11, L15, P09, P18, Q16, K04,	J06, D12, F16, G17, K07, K09, L05, P02, K18, K05, K06, K08,	F03, K10, P06, P11, P15, K15, L08, L07, K13, Q01	K12, K14, L09, L10, P11,

Table 8: potential platform capacity for conversion processes based on jacket mass/weight substructure.

Transmission systems

Various typologies of the offshore transmission system may arise, pure electric, pure molecule and combined systems consisting of both an electric part and a gaseous part. First some attention is given to the electric system, before discussing the various options for the gaseous system (dedicated/re-used/admixed). An electric transmission system is required to transport electricity to shore. This transport can either take place via a HVAC or HVDC system. The standardized typology for HVAC is 220kV; for HVDC this probably will be 320kV or 525kV. The overall system costs of such systems are analysed by the TOET-model developed in D3.8. A data matrix is developed for the various combinations of volume and distance (see page 57). There are, however, some limitations to the economic use of HVAC cables: its use is only economically feasible at distances up to 100km and at volumes up to 2GW**.** This limitation does not apply to HVDC typology systems, although these systems are relatively expensive for short distances and their substations for HVDC-systems are relatively expensive as well. Total costs reported in the public domain for a 1.4 GW HVDC system (incl. equipment, platform, cables and an onshore substation), vary between €2bn. (Viking) and €0.9bn (Gridlink). Because structure costs of offshore substations are estimated to be in the range of €0.4 to €0.5bn per item, installing energy islands generates the advantage that they may offer sufficient space for the transmission/converter processes and therefore save considerably on structure costs. Figure 25 and Figure 26 provide an overview of the cost matrix applied to the electric system designs. More generally, because islands provide space for energy system integration, also other synergy savings are likely. Note that project management costs are often not included in the assessment of the pros and cons of installing islands for energy system integration purposes. Such costs can be non-trivial: e.g. costs of surveys can easily add some 30% to the overall costs of the electric system. However, because in this study we assume that additional project management costs even out with the same type of costs in the case of pipeline systems, such costs are not considered either. This study discusses three options for hydrogen transport that have been defined in collaboration with WP 3.3. **Table 9: Summary of transport modes**

Table 9 gives an overview of the key differences of the various options in order to be able to assign and combine different parameters and to obtain differentiated transportation methods. The availability of the existing infrastructure will be determined by the decommissioning or end-of-production dates of each of the platforms and their connected pipelines. This information is not sufficiently public available yet in order to make a full assessment, and is moreover often uncertain. Therefore, the study takes into account the following estimate made by EBN[18] with regard to the throughput of the trunk lines for the upcoming years, and to quote EBN: “This is difficult to predict but with current information. A throughput could be defined as follows: 15 mln m³/day in 2020 with a linear decline till 2040 of 2 mln m³/day and subsequently a linear decline till 2050 of 0 mln m³/day.” Based on this trend, and as verified in WP 3.3, the main trunk lines (WGT, NGT and NOGAT) would only become available by 2050.

	Pipelines	Stream	Receiving pressure[19]	Pipeline requirements	Compression requirements	Other investments
TM 1	Existing	100% H2	68 bar	Retrofitting existing pipeline	Dedicated offshore H2 compressor	N/A
TM 2	New	100% H2	68 bar	New dedicated H2 pipeline	Dedicated offshore H2 compressor	N/A
TM 3	Existing	15 vol% Admix	68 bar	Existing pipelines	Similar offshore compressor	Gas separation costs

Table 9: Summary of transport modes

18 Information shared through email exchange with EBN within the context of the developing the research study [5].

19 Expert indicated that the onshore receiving pressure may be overestimated and that a pressure of 30 or 50 bar is currently assessed further (especially for exiting pipelines). This development will be in favour of the overall hydrogen developments, regardless of whether this will be offshore or onshore. For reasons of consistency the 68 bar is applied through the overall project line.

Existing dedicated hydrogen pipelines

This transport mode is characterised by its use of existing infrastructure with an output pressure of 68 bar and a 100% H2 stream. This pressure is in conformity with the common standard in the existing offshore gas network. Pipeline inspection is necessary to determine if anomalies are present. As indicated by D3.1 p.15: "all external risks will be the same regardless of whether or not hydrogen flows inside the pipeline; however, the resistance to them may be affected by the presence of hydrogen. It is therefore important to determine whether the base mechanical properties of the material are severely affected by the presence of hydrogen". Moreover, it is expected that a pure hydrogen stream requires dedicated compression equipment. The CAPEX and OPEX associated with dedicated hydrogen compression systems as well as the costs of retrofitting and OPEX of the existing infrastructure (pipelines and compression) are the main cost parameters. In this scenario costs of hydrogen infrastructure can be significantly reduced by reusing existing pipelines. The specific infrastructure requirements (diameter of pipelines and design pressure compressors) are calculated by a dynamic model based on the combinations of pipeline diameters and pressure (Table 10 and Table 11).[20] The outcomes are based on the assumption that the pipelines are corroding. Therefore, in line with (Gonzales - Diez, 2019) and the NORSOK standard, an epsilon factor, or surface roughness, of 0.5 mm has been applied. A limitation of 20 m/s has been set to the velocity at which hydrogen can be transported through the pipelines. A disadvantage of using existing pipeline infrastructure is that the infrastructure may not or not completely be available in time because part of the gas extraction facilities still needs it to transport natural gas to shore. Another risk is that the status of some of the existing pipelines reduces the options of pure hydrogen transport (e.g. due to risks of leakages and steel embrittlement).

Installed capacity windfarm (MW) / Distance (km)	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	12	12	12	12	12	12	12	14	14	14	14	14	14	14	14	14
2000	14	14	16	16	16	16	16	16	16	18	18	18	18	18	18	18
3000	18	18	18	18	18	18	18	20	20	20	20	20	20	20	20	22
4000	20	20	20	20	20	20	22	22	22	22	22	22	22	24	24	24
5000	22	22	22	22	22	22	22	24	24	24	24	24	24	26	26	26
6000	24	24	24	24	24	24	24	24	26	26	26	26	26	26	28	28
7000	26	26	26	26	26	26	26	26	26	28	28	28	28	28	28	28
8000	28	28	28	28	28	28	28	28	28	28	28	30	30	30	30	30
9000	30	30	30	30	30	30	30	30	30	30	30	30	30	32	32	32
10000	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32

Table 10: Minimum diameters of existing pipelines for various combinations of distance and installed capacity of offshore wind. The max. volume of hydrogen in kg/h that can be transported via the pipeline is determined by using a efficiency of 49kwh/kg and a 5% error-margin. The electrolyser capacity is set to equal the wind farm capacity with a load factor of 0.6.

Installed capacity windfarm (MW) / Distance (km)	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	83	86	88	91	94	97	99	84	85	86	87	88	90	91	92	93
2000	93	98	87	89	91	94	96	98	100	88	89	90	92	93	94	95
3000	84	87	89	92	95	98	100	90	92	93	95	97	99	100	100	90
4000	85	88	90	93	95	98	89	91	93	95	97	99	99	90	91	92
5000	84	87	89	92	94	97	99	91	93	94	96	97	99	91	92	93
6000	83	85	88	90	92	95	97	99	92	93	95	96	98	99	92	93
7000	81	83	85	87	89	92	94	96	98	92	93	95	96	97	99	100
8000	80	82	84	86	88	90	91	93	95	97	99	92	93	95	96	97
9000	79	81	82	84	86	88	89	91	93	94	96	98	99	93	94	95
10000	78	80	81	83	84	86	87	89	90	92	93	95	96	98	99	100

Table 11: Input pressure in existing pipelines for various combinations of distance and installed capacity of offshore wind. To illustrate, a 12 inch pipeline (see Table 10) is needed to transport 1000MW of wind energy as hydrogen over 100km. An input pressure of 97 bar is needed to overcome pressure drop and ensure that the hydrogen reaches shore at 68 bar without violating velocity-limitations. If a large pipeline (with lower input pressure) will be chosen as velocity-limitations (max. 20m/s) are violated, this may lead to input pressures going up and down.

[20] This model is developed by Hint within WP 3.4

New dedicated hydrogen pipeline

New dedicated pipelines are characterised by a higher epsilon factor, or surface roughness. This transport mode is typically designed for a 100% dedicated hydrogen stream with an output pressure of max. 68 bar. A limitation of 20 m/s has been set to the velocity at which hydrogen can be transported through such a pipeline. The CAPEX and OPEX of the new infrastructure (pipelines and compressors) are calculated by a dynamic model based on the combinations of pipeline diameters and pressure (Table 12 and Table 13). The method to construct associated costs follows the series of estimations made by EBN and Gasunie in their report ‘Transport en opslag van CO2 in Nederland’ (EBN, 2018). It states that on average; besides the pipeline material, two major factors are crucial for pipeline investment costs: the diameter and the distance to be covered. Generally, put, costs per kilometre decrease as the distance increases. The report estimates are based on market prices and worldwide realized projects. Because market prices were quite low at the measurement moment (2017), the estimates are assumed to have accuracy ranges from -20% to +40%. Other factors that can have a prominent impact on the costs of laying new pipelines include submarine obstacles (such as other pipes and cables), but also super-sea obstacles such as platforms or wind farms. All this may require that crossings need to be constructed. As this study does not focus on a specific location in the North Sea area, the concrete number and types of crossings has not been determined. Experience has learned, however, that this has little effect on the LCOE calculation. The CAPEX of new pipelines and compression is discussed more extensively in Appendix: Methodology pipeline and compression.

Transport of hydrogen in an admixed scenario

This scenario is especially relevant to investigate since natural gas production is expected to gradually decrease whereas the wind capacity will increase. The composition of the natural and hydrogen gas mixture will therefore change over the years as the volumes of natural gas decrease. This is an important point to consider since in the models the hydrogen share in the gas mixture is a assumed to be a limiting factor as a result of the regulatory regime and/or technological boundaries. For the regulatory part, the Gas Act regulates the transport of synthetic gas in the transport grid. The Netherlands ‘Ministry of Economic Affairs has set maximum levels of hydrogen content for the low calorific and high calorific transport grid: currently 0.02% for the H-gas and 0.5% for the L-gas system (see also D. 2.2 Regulatory Framework). These requirements do not apply to the offshore production network. However, by entering the onshore transport system the criteria mentioned have to be met. To illustrate, the onshore injection criteria for the WGT and local pipeline is respectively 0.02%Mol and 0.5%Mol. In practice, this means that either the offshore injection rate is limited by the onshore criteria, or that the gas mixture needs to be treated onshore in a gas separation plant. The technical limitation of hydrogen admixture in the natural gas system is assumed to be determined by the receiving equipment of the onshore gas treatment plant. As discussed with EBN, a maximum of 15 vol% of hydrogen in the offshore natural gas mix is therefore assumed (Niessen, 2018). The input pressure and pipeline characteristics of existing pipelines in our scenarios are based on this assumption. The reason is that the weight and density effect on hydrogen transport will even each-other out. Because of its lower molecular weight and viscosity, hydrogen flows move 2–2.5 times faster than natural gas in a pipeline under the same conditions of pipe diameter and pressure drop. However, because of the lower heating value of hydrogen, a hydrogen pipeline carries about 30%–40% less energy than a natural-gas pipeline. Next, it is uncertain what the exact composition of the admixture will be, hence it is better to take a conservative approach on the surface roughness. In case of admixture, larger pipelines would be required to transport the same amount of hydrogen due to the assumed 15% limitation. To illustrate, a 10-inch pipeline would be sufficient to transport about 10,000 kg/h of 100% pure hydrogen, whereas at least a 20-inch pipeline would be needed to also transport the additional natural gas stream next to hydrogen, while maintaining pressure levels.

Installed capacity windfarm (MW)																Distance (km)
	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	10	10	10	12	12	12	12	12	12	12	12	12	12	12	12	14
2000	14	14	14	14	14	14	16	16	16	16	16	16	16	16	16	16
3000	16	18	18	18	18	18	18	18	18	18	18	18	18	20	20	20
4000	20	20	20	20	20	20	20	20	20	20	20	20	20	22	22	22
5000	22	22	22	22	22	22	22	22	22	22	22	22	22	22	24	24
6000	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24

7000	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
8000	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
9000	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
10000	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30

Table 12: Minimum diameters of new pipelines for various combinations of distance and installed capacity of offshore wind. The max. volume of hydrogen in kg/h that can be transported via the pipeline is determined by using a efficiency of 49kWh/kg and a 5% error-margin. The electrolyser capacity is set to equal the wind farm capacity with a load factor of 0.6.

Installed capacity windfarm (MW)																Distance (km)
	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	91	95	98	83	85	86	88	90	91	93	94	96	97	99	100	85
2000	85	87	89.8	92.6	95.4	98	86	87.6	89.2	90.8	92.4	94	95.6	97.2	98.8	99
3000	86	81	82.5	84	85.5	87	88.5	90	91.5	93	94.5	96	99	88	89.5	91
4000	79	80.8	82.6	84.4	86.2	88	89.8	91.6	93.4	95.2	97	98.8	100	90	91	92
5000	79	80.6	82.2	83.8	85.4	87	88.6	90.2	91.8	93.4	95	96.6	98.2	100	91	92
6000	78	79.6	81.2	82.8	84.4	86	87.6	89.2	90.8	92.4	94	95.6	97.2	98.8	100	101
7000	77	78.5	80	81.5	83	84.5	86	87.5	89	90.5	92	93.5	95	96.5	98	98
8000	76	77.4	78.8	80.2	81.6	83	84.4	85.8	87.2	88.6	90	91.4	92.8	94.2	95.6	95
9000	75	76.3	77.6	78.9	80.2	81.5	82.8	84.1	85.4	86.7	88	89.3	90.6	91.9	93.2	93
10000	77	78.4	79.8	81.2	82.6	84	85.4	86.8	88.2	89.6	91	92.4	93.8	95.2	96.6	97

Table 13: Input pressure of dedicated pipelines for various combinations of distance and installed capacity of offshore wind. To illustrate, a 12 inch pipeline (see Table 12) is needed to transport 1000MW of wind energy as hydrogen over 100km. An input pressure of 86 bar is needed to overcome pressure drop and ensure that the hydrogen reaches shore at 68 bar, without violating velocity-limitations. If a large pipeline (with lower input pressure) will be chosen as velocity-limitations (max. 20m/s) are violated, this may lead input pressures to go up and down.

Offshore system calculations

The result of the offshore system calculations for each system is presented in the form of a single (KPI-like) value: the allowable offshore cost factor for offshore hydrogen production. The matrix displays at which offshore cost factors one would still prefer offshore hydrogen production for economic reasons. One has to be careful in interpreting these results, however, because much uncertainties do exist with regard to additional cost levels of installing, operating and maintaining offshore systems. Offshore hydrogen production is expected to be more expensive than onshore production, given the environmental circumstances that are likely to increase the installation, operation and maintenance costs. Although, experience can be taken from gas production on offshore platforms, the Maasvlakte, or the Dutch islands, much is still unknown about the actual offshore costs factor for offshore hydrogen production. Hence, the allowable cost factor (%) provides insight in the additional costs in percentages for offshore production at which it still breaks-even with onshore hydrogen production. Based on this cost factor, stakeholders (both gas and wind operators) can decide whether an offshore area, characterized by distance and potential for offshore wind capacity, has economic potential for offshore hydrogen production.

The model is developed in such a manner that it indicates the allowable cost factor per scenario, though, the composition of the model does not allow for a direct comparison between hydrogen production on platforms, new platforms and/or islands. Hence, it only compares the cost of a specific offshore production mode with onshore production given a pre-defined system design. In case of platforms, it compares offshore production of hydrogen on platforms to onshore production whereby electricity transmission takes place via substations on platforms. In case of islands, it compares offshore production to onshore production in which electricity transmission takes place via substations on islands. So, the transmission mode of electricity in the base case varies for the various hydrogen production substructures analysed. The implication is that if existing hybrid platforms indicate a higher allowable offshore cost factor than hybrid energy islands, then one cannot conclude from it that platform constructions are generally more preferable than hybrid energy islands, because the electrical reference case differs between both scenarios. The main parameters used as input for the electrolyser process are described in Table 14. A set of boundary conditions are met in the model:

- The main input variable is the total installed capacity of offshore wind with a load factor of 60%;
- Hydrogen is delivered at a pressure of 68 bar onshore;
- Re-use of by-products heat and oxygen is not assessed;
- The model can be used to simulate optima with different volumes, distances and technologies;
- Distances used are shortest distance to shore;
- The main output is assessing the cost levels at which offshore hydrogen costs are equal to onshore production cost; other criteria may lead to other outcomes
- The project lifetime is set at 20 years and a WACC of 10% is applied;
- The location of the electrolyser is determined on a cost-efficiency basis (NPV comparison);

	2030 onshore	2030 offshore	>2040 onshore	>2040 offshore
Outlet pressure	30	30	30	30
Power consumption at Pnom (kWh/kg)	49	49	49	49
Water consumption (l/kg)	1000	5650	5650	1500
Lifetime stack (years)	2000	11300	11300	3000
Lifetime – system (years)	20	20	20	20
Stack at full charge (hr)	60000	60000	60000	60000
CAPEX (total) (€/kW)	988	1132	538	593.85
OPEX (% of CAPEX)	2%	2%	2%	2%
Capex stack replacement (€/kW)	200	203	200	203
Desalination unit €/kW	3500	3500	3500	3500
Power consumption kW/h	376	376	376	376

Table 14: Main parameters electrolyser based on D3.2 and D3.8

Outcomes offshore cost factors

Outcomes for 2020-2030

Current policy plans of the Netherlands' government suggest that for the period 2020-2030 one intends to predominantly install the planned 11.5GW offshore wind capacity with the help of an electric connection to shore. First it should be mentioned that although the need for flexibility slightly differs between the two hybrid scenarios, the main conclusions are similar, namely (see Figure 13) that at the current prices for carbon free hydrogen and without the investors in conversion capacity being reimbursed for public savings on electricity grid investment there is not much evidence that re-use of existing platforms for conversion purposes will be an economically interesting option in the period between 2020 and 2030. In fact, as was argued already, it is likely that the installation and maintenance of electrolysers systems offshore will lead to higher costs than if those would have been installed onshore, such that it is uncertain if those extra costs would outweigh the grid savings or flexibility revenues. These results (see Figure 13a) have been found both for the case in which pure hydrogen will be transported to shore, as well as for the cases in which the hydrogen is admixed and subsequently separated again during its transport with the help of the gas grid.

A: existing platform, existing pipelines

Installed wind capacity in 2030 [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	138%	140%	141%	145%	145%	147%	149%	150%
2000	97%	100%	102%	119%	120%	121%	123%	124%
3000	158%	157%	155%	122%	124%	126%	128%	130%
4000	130%	132%	134%	135%	137%	139%	141%	143%
5000	126%	127%	129%	130%	131%	133%	134%	136%
6000	135%	137%	139%	140%	142%	144%	146%	148%
7000	132%	133%	135%	137%	139%	141%	143%	145%
8000	137%	139%	141%	142%	144%	146%	148%	150%
9000	135%	137%	139%	141%	143%	145%	147%	150%
10000	138%	140%	141%	143%	145%	147%	149%	150%

B: new platform, dedicate pipeline

Installed wind capacity in 2030 [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	122%	124%	125%	128%	128%	129%	131%	132%
2000	85%	86%	87%	101%	102%	102%	102%	103%
3000	135%	134%	132%	104%	105%	106%	107%	108%
4000	115%	116%	117%	118%	119%	120%	122%	123%
5000	109%	110%	111%	112%	113%	114%	115%	116%
6000	119%	121%	122%	123%	125%	126%	128%	129%
7000	115%	117%	118%	119%	121%	122%	123%	125%
8000	121%	123%	124%	126%	127%	128%	130%	131%
9000	118%	120%	122%	123%	125%	127%	128%	130%
10000	122%	124%	125%	126%	128%	129%	131%	132%

C: islands, dedicated pipeline

Installed wind capacity in 2030 [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	129%	130%	132%	135%	135%	137%	139%	141%
2000	86%	87%	88%	83%	82%	81%	82%	82%
3000	126%	123%	121%	106%	107%	108%	110%	111%
4000	107%	108%	109%	110%	112%	113%	114%	115%
5000	109%	109%	110%	112%	113%	114%	115%	116%
6000	125%	126%	128%	130%	131%	133%	135%	137%
7000	126%	128%	130%	132%	133%	135%	137%	139%
8000	128%	129%	131%	133%	134%	136%	138%	140%
9000	129%	131%	133%	135%	137%	139%	141%	144%
10000	129%	130%	132%	134%	135%	137%	139%	141%

Figure 13: Outcomes of the NSE-National Management scenario for 2030 with a: an existing platform and existing pipeline combinations. The outcomes of admixture and 100% re-use are in the same line. b: new platform and new pipelines. c: islands in combination with new pipelines.
Note: an allowable cost factor of 140% means that offshore hydrogen production costs can be 140% higher than those of onshore hydrogen production to still break even.

The conclusion from this seems clear: offshore conversion can only generate a promising business case in the next 5 to 10 years if at least one of the following conditions is fulfilled: electrolysers can successfully compete with other flexibility technologies[21], substantially higher carbon free hydrogen prices, or internalising via policies and measures the public grid savings such that they accrue to those investors in offshore conversion that have generated them for the taxpayers. Besides that, experimenting with offshore conversion obviously may be useful and even desirable from a social welfare perspective to learn and be ready once more favourable conditions apply. Given these overall conclusions the finding from Figure 13b namely, that hybrid offshore conversion options involving completely new platforms and hydrogen transport systems do not have a short-term business case either (under similar pessimistic assumptions towards hydrogen prices and grid cost internalising options), is self-evident. The same conclusion applies for the option to create energy islands with the prime purpose of power-to-gas energy conversion (see Figure 13c).

Outcomes towards 2040 and 2050

For the period 2030-2050, at least some additional 40 GW offshore wind capacity would need to be installed per decade to realise the total North Sea countries' collective ambitions for extending offshore wind capacity by 2050. This rapid development of offshore wind is expected to go hand in hand with both the increasing demand for carbon free hydrogen for energy and feedstock purposes and the increasing demand for flexibility for the electricity grid. It is therefore expected that under the NSE - National Management scenario the need for conversion of offshore wind into hydrogen will remain stable at 49% and 43% (see Table 1 and Table 2). Figure 14a shows that the outcomes for these cases are quite different from those for the 2020-2030 period. It shows that given the new conditions holding for the post 2030 period re-use of existing platforms for conversion purposes does generate positive returns. Especially platforms located further offshore (e.g. >120km) can be considered to be interesting potential locations for hybrid offshore hydrogen production, but the more time progresses the more positive business cases for such conversion appear for platforms located nearer to shore (<100 km) especially if the cost differential between onshore and offshore conversion investment costs reduces to e.g. a factor of, say, 150%.

[21] Infrastructure Outlook 2050 expects hydrogen to play a serious role in providing flexibility to the power markets with the help of electrolysers. This requires that the technology can compete successfully with other flex-technologies and therefore that: the CAPEX of electrolyser technologies comes down significantly, and various externalities are internalised (incl. those related to long-term security of supply). The model assumes a stack price of 700€/kW (in 2030) and 400€/kW (in 2040)

A: existing platform, existing pipelines

Installed wind capacity in 2040& 2050 [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	168%	170%	173%	178%	178%	181%	184%	186%
2000	104%	108%	111%	138%	140%	141%	143%	145%
3000	195%	193%	190%	141%	144%	146%	149%	152%
4000	156%	158%	161%	163%	166%	169%	172%	175%
5000	147%	149%	151%	153%	155%	158%	160%	162%
6000	163%	165%	168%	171%	174%	177%	180%	183%
7000	157%	159%	162%	164%	167%	170%	173%	176%
8000	166%	169%	172%	174%	177%	180%	183%	186%
9000	162%	165%	168%	171%	174%	177%	180%	184%
10000	168%	170%	173%	175%	178%	181%	184%	186%

B: new platform, dedicate pipeline

Installed wind capacity in 2040& 2050 [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	140%	142%	143%	147%	147%	149%	151%	153%
2000	85%	86%	88%	109%	109%	109%	110%	110%
3000	156%	153%	151%	111%	112%	114%	115%	116%
4000	128%	130%	132%	133%	135%	136%	138%	139%
5000	120%	121%	122%	124%	125%	126%	127%	129%
6000	135%	137%	139%	141%	143%	145%	147%	149%
7000	129%	131%	133%	134%	136%	138%	140%	142%
8000	139%	140%	142%	144%	146%	148%	150%	152%
9000	134%	136%	138%	140%	142%	145%	147%	149%
10000	140%	142%	143%	145%	147%	149%	151%	153%

C: islands, dedicated pipeline

Installed wind capacity in 2040& 2050 [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	160%	163%	165%	170%	170%	173%	176%	179%
2000	87%	88%	90%	83%	81%	80%	80%	80%
3000	150%	146%	142%	118%	119%	121%	123%	125%
4000	120%	121%	123%	125%	127%	129%	130%	132%
5000	124%	124%	125%	127%	128%	130%	131%	133%
6000	153%	156%	158%	161%	163%	166%	169%	171%
7000	156%	159%	162%	164%	167%	170%	172%	175%
8000	158%	161%	164%	166%	168%	171%	174%	177%
9000	161%	164%	167%	171%	174%	177%	180%	184%
10000	160%	163%	165%	168%	170%	173%	176%	179%

Figure 14: Outcomes of the NSE-National Management scenario for 2040 and 2050 with a: an existing platform and existing pipeline combinations. The outcomes of admixture and 100% re-use are in the same line. b: new platform and new pipelines. c: islands in combination with new pipelines.

The option of combining conversion with a admixing the hydrogen to the natural gas still transported via the gas grid to shore remains, however, problematic also on the longer term. A main reason is linked to separation costs (in order to avoid to get the low natural gas price for carbon free hydrogen). Another reason has to do with the assumption that admixing rates will remain restrained to e.g. some 15% only. Under such a regime the flow of hydrogen is simply too low to get to an economically feasible result. Also, like in the hybrid case for the 2020-2030 period, installing new platforms and pipeline systems for hybrid offshore hydrogen production is not a long-term option. The concept of creating offshore energy conversion islands – that obviously could provide many other energy and non-energy functions as well – turns out to also become feasible in the post 2030 period. The main conditions for these investments to generate a positive business case are if sufficient economics of scale can be generated, so if wind capacities are sizeable enough, and whether there is sufficient distance from shore such that grid savings become substantial enough. We found for the post 2030 period that for higher wind capacities in the order of 6 GW, energy islands can become economically positive options, the more so as they are located further (more than 100 km) from shore (Figure 14c).

Outcomes 100% conversion

Dedicated hydrogen production, so converting all wind power into hydrogen so that an electricity grid connection between the offshore wind farm and shore is no longer needed, on the whole shows a greater preference for offshore conversion configurations. This is logical because grid savings will be larger and overall the system is simpler, although less flexible, than the cost for the onshore system are slightly higher. This explains the finding that re-use of existing platforms for dedicated hydrogen production already generates positive returns if located at shorter distance from shore than comparable hybrid cases. Again, just as in the hybrid cases admixing hydrogen into the natural gas flows does not seem to offer a good economic return for the reasons already mentioned before. Interestingly enough, Figure 15c shows that for the 100% conversion case both the installation of new platforms and the establishment of energy islands seems to offer good economic long-term potential, and should therefore be investigated further in greater detail.

A: existing platform, existing pipelines

Installed wind capacity [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	160%	160%	160%	160%	160%	160%	160%	160%
2000	157%	166%	175%	234%	238%	244%	249%	254%
3000	205%	209%	214%	218%	223%	228%	233%	237%
4000	218%	223%	227%	232%	237%	241%	246%	251%
5000	209%	213%	217%	221%	226%	230%	234%	239%
6000	218%	222%	227%	231%	236%	241%	245%	250%
7000	212%	216%	220%	225%	229%	234%	238%	243%
8000	218%	223%	227%	232%	236%	241%	246%	251%
9000	213%	218%	222%	227%	231%	236%	240%	245%
10000	245%	245%	245%	245%	245%	245%	245%	245%

B: new platform, dedicate pipeline

Installed wind capacity [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	194%	198%	201%	208%	208%	212%	215%	219%
2000	137%	145%	152%	202%	205%	208%	211%	213%
3000	177%	180%	184%	187%	190%	194%	196%	200%
4000	194%	197%	200%	204%	207%	211%	214%	218%
5000	183%	186%	189%	192%	196%	199%	202%	206%
6000	194%	198%	201%	205%	209%	212%	216%	219%
7000	186%	190%	193%	196%	200%	203%	206%	210%
8000	195%	198%	202%	205%	209%	212%	216%	220%
9000	189%	192%	196%	199%	203%	206%	210%	214%
10000	194%	198%	201%	204%	208%	212%	215%	219%

C: islands, dedicated pipeline

Installed wind capacity [in MW] \ Distance [in km]	60	80	100	120	140	160	180	200
1000	186%	190%	194%	202%	202%	206%	211%	215%
2000	128%	135%	142%	154%	157%	160%	163%	166%
3000	174%	178%	182%	186%	190%	194%	197%	201%
4000	173%	177%	180%	184%	188%	192%	196%	200%
5000	173%	177%	180%	184%	188%	192%	196%	200%
6000	186%	190%	194%	199%	203%	207%	212%	216%
7000	186%	190%	194%	198%	202%	206%	211%	215%
8000	186%	191%	195%	199%	203%	208%	212%	216%
9000	187%	191%	195%	200%	204%	209%	213%	217%
10000	186%	190%	194%	198%	202%	206%	211%	215%

Figure 15: Outcomes dedicated hydrogen production scenario for 2040 and 2050 with a: an existing platform and existing pipeline combinations. The outcomes of admixture and 100% re-use are in the same line. b: new platform and new pipelines. c: islands in combination with new pipelines.

A perspective on these system calculations

NSE – National management scenario

As was argued already before, unless serious policies and measures are taken at short notice to improve the business case of offshore conversion of wind power into hydrogen, the start of hydrogen production in de period up to 2030 will most likely be concentrated on onshore locations. That would mean that for the time being the projected 11.5 GW of offshore wind capacity projected to be installed by 2030 on the Netherlands' continental shelf of the North Sea, will generate power that will predominantly need to be transported to shore via electricity grid connections, probably in conjunction with AC/DC and DC/AC conversion. In order to deal with emerging electricity grid congestion issues,

the need for interconnection points will increase rapidly, for which Eemshaven, Beverwijk, and the Maasvlakte seem to be the most likely candidates.
At the same time, however, it seems unlikely that during the next decade in the Netherlands no progress will be made towards setting up and installing offshore conversion capacity. In fact concrete pilots and even larger-scale initiatives on this are now already (2019) initiated or are in preparation by some North Sea operators. There are a number of reasons why offshore conversion is expected to already develop well before 2030. First, there is increasing evidence that within the period 2030 to 2040 offshore conversion will have a business case. Our modelling results corroborate that view. Operators are expected to prepare for that and already take action well in advance to prepare for their own business and competitive future. Second, offshore conversion cannot be implemented at serious scale overnight. One has to get through the common learning stages involving a pilot and demonstration phase before commercial stages can be reached. Such preparatory stages can easily take about a decade, especially under the challenging offshore conditions at hand. Third, congestion challenges in the electricity grid as well as costs to try to deal with them, are a serious problem in the Netherlands case. The TSO TenneT indicated at several instances that congestion problems can become serious already before the 11.5GW projected offshore wind capacity is installed. Based on public cost considerations, congestion threats, and general resistance against new electricity grid infrastructure investment, public and political pressure in favour of offshore conversion may therefore build up much earlier than by 2030.
Based on these considerations, as well as the perspective that the Netherlands may be in the position to develop a competitive edge based on offshore conversion technologies and more generally the implementation of hydrogen in various sectors, it is likely that serious pioneering activity on offshore conversion may develop in the period leading up to 2030. A fortunate point in this regard is that so far some 900MW offshore wind capacity to be installed by 2030 has not yet been assigned to a particular location. If that capacity would be used for experimenting with offshore conversion options/technologies, there still are some degrees of freedom to find the most suitable location for this. So, if the above view is correct, the question arises which locations on the North Sea are best suited to initiate offshore conversion pilots or even demos possibly based on different technologies and constructs. Three locations seem to be prime candidates for hosting such activity (although not necessarily the only ones): Q13a platform located at eight miles from the coast, the top of offshore wind site IJmuiden-Ver, and the offshore region at which the first Netherlands' offshore wind farm has been installed, commonly referred to as North of the Wadden. Below we will discuss these options shortly. It should be mentioned upfront that it is not necessary a priori to choose between the options; in fact all locations could simultaneously be developed as pilot offshore conversion sites so that one can benefit from the differences in site-specific conditions to enhance learning results.

Q13a – Poseidon
The Q13a platform, operated by Neptune, is chosen to become the first offshore platform site that will produce hydrogen from electricity. Although, the electricity still comes from shore, the demonstration of hydrogen production in an environment that is characterised as being harsh, is a necessary first step to reduce future costs for offshore hydrogen production. The platform is due to begin production later in 2021[22] and will provide the stakeholders involved with the experience necessary to produce hydrogen in an offshore environment.

North of IJmuiden-Ver
The tender procedure for the IJmuiden-Ver 4GW offshore wind farm area will start in 2026; commissioning is expected to be finalised by 2030. The location is interesting for offshore conversion experiments due to its proximity to the O&G platforms located in the K-block. Re-use of the substructures of the K14 and K15 platforms could enable to install an additional 300MW of offshore wind capacity in the area before 2030 without altering the electric transmission network[23]. There may, however, be a challenge with regard to an intended re-use of the existing platforms, since both the K14 and K15 platforms are not expected to be decommissioned before 2027 (NSE-Atlas, 2019). A similar

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[22] https://www.offshorewind.biz/2019/10/23/poshydon-first-green-offshore-hydrogen-pilot-explained-video/
[23] On the basis of weight carrying capacity, K14 and K15 could host about 300-400 MW of conversion capacity (see Table 8: potential platform capacity for conversion processes based on jacket mass/weight substructure.). .

issue does not seem to apply for the re-use of the pipeline infrastructure. Although, the K14 block is currently connected to the WGT trunk line, an extension of K15 via the Local-pipeline to K14 is possible. The 24-inch local would be able to transport total wind capacity of 6GW without violating the velocity limitation of 20m/s. This would then reduce the need for admixture significantly, which is important because the economics of admixing seem to be worse than of dedicated hydrogen transport. If yet admixing would turn out to be the only viable option, there does not seem to be a serious limitation in this case because the WGT trunk line is projected to transport so much natural gas up to 2030 that a 15 or 20% admixture limit would still be compatible with the transport capacity given the projected volumes of hydrogen to be transported.

North of the Wadden
The second area suitable as location for initiating offshore conversion activity is located left from the windfarm called 'North of the Wadden' (TNW). This capacity will be tendered in 2022 and is scheduled to be commissioned in 2026. Some 700 MW of wind capacity is planned to be located in this area, although this capacity may be extended to some 800 MW, which can in combination with hybrid hydrogen production installed without actually possible without adjusting the electric transmission system. The power generated from such additional 100 MW of wind capacity could, for instance, be converted on the existing platforms in the G-block. Based on substructure data of Ospar, it can be estimated that conversion of wind power into hydrogen on these platforms combined could provide some 12.5% of the flexibility needed to optimise the energy system and prevent congestion on the electricity grid[24]. The flexibility needed to balance power supply of the remaining part of the wind park could be provided by onshore hydrogen conversion in the Eemshaven region. With the current planned capacity an island solution is of no economic interest (yet) for this tender area. Because the platforms at the G17 block will most likely be decommissioned somewhere between 2023-2027 (NSE-Atlas, 2019), early hydrogen production at the G-blocks can first be admixed into the NGT-grid. More research is required regarding admixture options for the situation in which the G-blocks will be out of production. If it would be necessary to install a new pipeline from the G-block to shore, offshore conversion from the TNW area seems economically less attractive.

2030-2040

In the period 2030-2040 a linear increase in offshore wind capacity is expected resulting in a total installed capacity of 32.5 GW by 2040. In the National Management scenario some 49% of the wind energy produced will be converted to hydrogen for reasons of providing flexibility alone. If carbon free hydrogen would be required for its own sake, the percentage could even become higher. The general picture resulting from the simulations clearly indicates that re-use of existing infrastructure is typically the preferred option if energy production and conversion takes place at large distance from shore (starting from 140 km), and at almost 5GW to 6GW capacity of offshore wind.[25] Island constructions generally become more favourable as the distance and/or energy volume increases, which can be explained by the economies of scale given the large fixed costs related to the construction of artificial islands. Simulations revealed that island constructions were the economically preferred option in the same cases as those in which some shorter distances to shore were combined with large wind capacities (for an overview of cases in which island constructions were optimal, see Table 15). Table 15 shows the optimal location while setting the allowable costs factor at 175%. This implies that the costs for offshore hydrogen production (either at platform or island) are increased with 175%, and the outcomes (LCOE) expressed in €/MWh in various system typologies. The comparison of the outcomes indicated that hybrid hydrogen production becomes preferable from an economic perspective at a scale of 6,000MW. For smaller volumes, all-electric, either via platform or via island, it is economically preferable on the basis of LCOE in €/MWh. However, in some cases onshore hydrogen production is preferred to cases wherein electricity is transmitted via energy islands, but offshore would be the preferred option if instead platforms would be used for transmission. For the hybrid hydrogen case

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24 On the basis of weight carrying capacity, G17, G14, G16 could host about 100 MW of conversion capacity (see Table 8: potential platform capacity for conversion processes based on jacket mass/weight substructure.). 100MW of conversion capacity on a total capacity of wind installed of 800MW lead to flexibility of 12.5%.

25 Chapter 7 points out that economics of scale for platforms structure are limited. Platform structure costs are about 0.3 M€/MW of wind capacity installed and do not decrease significantly as capacity increases.

offshore conversion seems to be of particular interest for area G and C/D with shortest distances to shore of 130 km and 110 km, respectively (see also Appendix: NSE - National Management). 'Innovation areas' at these locations can be used as stepping stones for offshore hydrogen production. Re-use of the existing pipeline infrastructure (100% hydrogen transport) may be an option for longer transport distances, although it should be pointed out that in this area most wind parks are actually located within a 140 km distance range from shore.

Installed wind capacity [in MW]	Distance [in km] 60	80	100	120	140	160	180	200
1000	onshore	onshore	onshore	onshore	onshore	onshore	onshore	onshore
2000	onshore	onshore	onshore	onshore	onshore	onshore	onshore	onshore
3000	onshore	onshore	onshore	onshore	onshore	onshore	onshore	onshore
4000	onshore	onshore	onshore	onshore	onshore	onshore	onshore	onshore
5000	onshore	onshore	onshore	onshore	onshore	onshore	onshore	onshore
6000	Island	Island	Island	Island	Island	Island	Island	Island
7000	Island	Island	Island	Island	Island	Island	Island	Island
8000	Island	Island	Island	Island	Island	Island	Island	Island
9000	Island	Island	Island	Island	Island	Island	Island	Island
10000	Island	Island	Island	Island	Island	Island	Island	Island

Table 15: Optimal location for cases of hybrid hydrogen production by 2040 and 2050. Red indicates that onshore conversion is the preferred option, whereby either platforms or islands may transmit the electricity. Green indicates that onshore hydrogen production is preferred if electricity is transmitted via energy islands, but that if platforms would be used for transmission offshore conversion becomes preferable.

2040-2050

In the period 2040-2050 a further linear increase in offshore wind capacity is assumed resulting in a capacity of 53 GW by 2050. In the National Management scenario now some 49% of the wind energy produced will be converted to hydrogen for reasons of flexibility demand only. In this period island constructions are expected to become economically very favourable (for more detailed simulation results, see Table 15). By 2050 most of the Netherlands' offshore wind capacity will be located outside the 200 km range and, given the high volumes of offshore wind energy expected to be installed by then and the persistent economies of scale of island constructions, overall costs of islands (as compared to other options for conversion locations) may have come down significantly. Figure 16 gives an artist impression of the above simulations per scenario. It sketches, once again, that until 2030 flexibility (in this case hydrogen production) is most likely to be provided most economically at the interconnection point at shore. However, the development of 'innovation areas' to gain operational expertise with offshore conversion may be of great strategic importance and necessary learning impact, because our simulations suggest that offshore conversion already can be preferable over onshore conversion towards 2030. For some of the energy islands the existing gas grid may be well suited to transport the carbon free hydrogen to shore. For those cases it has been assumed that where the hydrogen gets to shore an onshore hydrogen grid (potentially based on the existing gas grid) is available by 2030, such that the point of connection with the onshore gas grid is of less relevance. Between 2040 and 2050 the location of newly constructed wind farms is projected to be far-offshore. That far away from shore existing gas grids are on the whole relatively scarce so that mostly new pipelines will be required to transport the energy molecules to the market. It should be mentioned in this regard that a potential positive externality of developing new offshore gas transport infrastructure is that it enables the competitive exploitation of proven O&G reserves that otherwise would not have been economically feasible to explore. The alternative I scenario shows that some 7 GW of installed wind capacity may be dedicated to hydrogen production (see Appendix: Model input alternative). This dedicated hydrogen is needed to fulfil the high-demand for hydrogen in this scenario. The optimal configuration resulting from page 32 suggests that once the installation of offshore wind capacity reaches its level of completion on the Netherlands' continental shelf, i.e. by about 2050, ideally about 3 to 5 energy islands broadly spread over the offshore area should have been constructed by then, on which the conversion to carbon free hydrogen, both hybrid and dedicated hydrogen and possibly various other economic activities, can take place.

NSE – Regional Management scenario

In the Regional Management scenario (unlike the National management scenario) much of the flexibility to be provided to the electricity system is expected to be generated onshore and regionally. This explains why the role of conversion offshore is generally less developed than in the former scenario. Figure 17 gives an artist impression of the scenario for the different view years leading up to 2050. It shows that during 2020-2030, energy conversion initiatives follow more or less the same pattern as in the National management scenario: onshore hydrogen production is likely to be dominant, although there will be scope for initiatives towards offshore conversion. The serious allocation of offshore wind locations to also realise dedicated conversion and therefore hydrogen production will start by about 2030, as demand for electricity from regional sources of solar and onshore wind will enhance the demand for flexibility of the e-grid. The further development of offshore conversion capacities and the construction of islands for that purposes will gradually develop in this scenario, but less fast and significant than in the alternative National Management scenario shown before. The number of islands is projected to also be less nearing 2050.

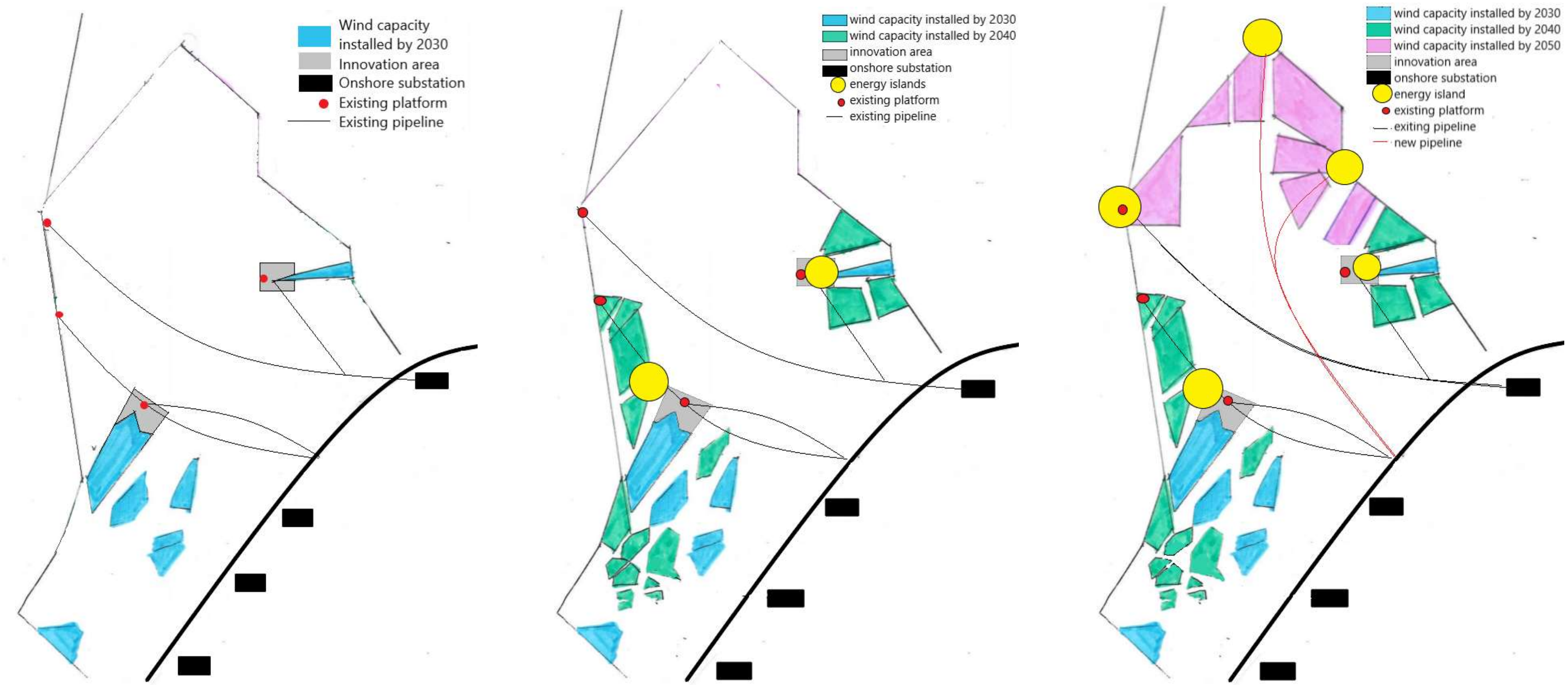

Figure 16: Artist impression of NSE – National Management scenario (from left to right the developments for 2030, 2040 and 2050 are sketched). Note that the fictive locations and routes of offshore energy potential and infrastructure are for illustrative purpose only. This should not be interpreted as final or preferential locations for offshore system integration projects.

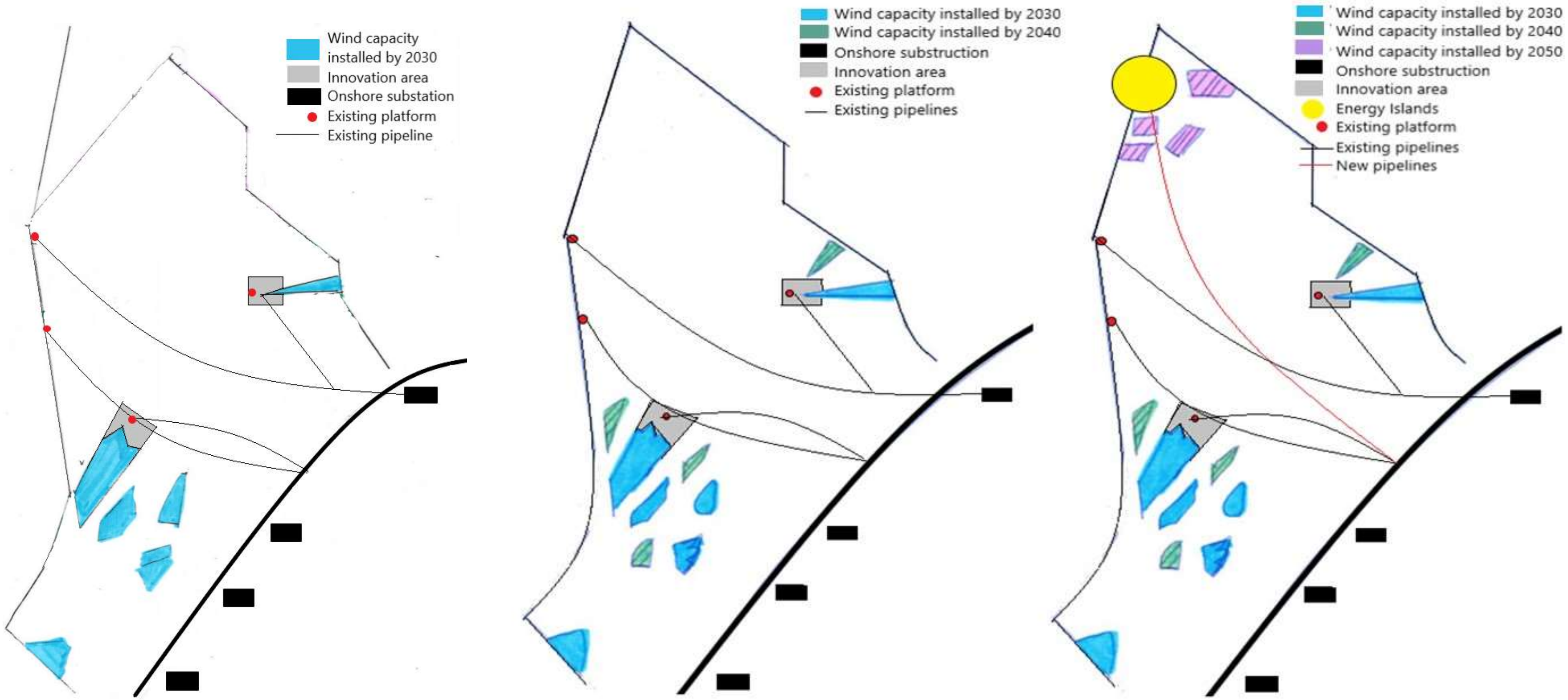

Figure 17: Artist impression of NSE - Regional Management (from left to right the developments for 2030, 2040 and 2050 are sketched). Note that the fictive locations and routes of offshore energy potential and infrastructure are for illustrative purpose only. This should not be interpreted as final or preferential locations for offshore system integration projects.

Market imperfections

In the following, we will distinguish three main reasons why a particular technology, in this case power-to-gas, will not or too slowly become economically attractive to make the desired optimal contribution to the energy transition and especially its applicability at an offshore location:

- Investment in this technology may not happen because the investor does not include a number of relevant aspects from an overall socio-economic perspective (system costs/benefits, externalities, and macro-economic and geo-political impacts) into the NPV analysis, whereas such aspects would have had a positive impact on investment if included;
- Investors facing the traditional ‘valley-of-death’ in the evolution of a new technology, are not prepared individually to take the risk of being the first-mover, among others because they fear by doing so to benefit competitors;
- Investors are afraid to invest in technology generating products, in this case carbon free hydrogen, of which they have insufficiently clear perspectives on their future prices and demand in the absence of a sufficiently developed market for this output.

In the following, we will subsequently discuss these three reasons for potential market failure. Each of them may block progress towards power-to-gas development. All therefore need to be addressed by policy makers or otherwise to get to the optimal energy transition profile.

Ignoring externalities and system costs

In answering the issue whether or not a specific technology would need to be introduced, several criteria can be distinguished, depending on the scope of the costs and benefits that are included in the ultimate decision analysis. Most projects are assessed by the potential investor on the basis of plant-level costs. That is to say, the various CAPEX and OPEX costs on the one hand and the expected returns on the other are weighed against each other in an NPV analysis, whereby only those costs and benefits are taken into account that accrue directly to the investor. Commonly, sensitivity analyses are carried out covering the various uncertainties and statistical margins in order to get a right perspective on both the NPV and its potential ranges. A typical example is the investment in an electrolyser plant, with the purpose to turn carbon free power into hydrogen. The investor will collect data on the CAPEX and OPEX of the electrolyser itself and the related equipment needed, the costs of the input (power), and the returns on the output (hydrogen and possibly oxygen and heat). Some additional costs related to the specific location and management and other operational costs will be included in the equation. Finally, this analysis underpins whether or not the expected financial return is acceptable given the expected return level and uncertainty margins.
Such an assessment suffers from a number of weaknesses if a broader, societal perspective is taken to try to answer the question whether or not such a technology should be initiated. First, a technology should not be considered in isolation, but is always linked to the other parts of the value chain it is part of. An electrolyser, for instance, is capable of converting power into hydrogen, but the further value chain covers the transport impact of this technology, the potential to store energy, and the degree to which energy in this form (hydrogen) can be applied. The same technology will also have implications for the wider energy system insofar as the risk of curtailing renewable power from wind or solar is affected, or the ease of electricity grid balancing. In the following, such costs will be referred to as ‘system costs’ that are external to the investor in the electrolyser technology, but can be typically allocated to other stakeholders such as the government or energy DSOs and TSOs (and eventually potentially energy end users).
Next to the system costs, the typical external costs can be distinguished, i.e. costs that cannot be assigned to specific stakeholders or economic agents, but are rather borne by society as a whole. Typical examples are greenhouse gas emissions, local pollutants (including their health effects), safety levels, landscape and noise impacts, ecosystems, and biodiversity. Just like public goods, so can externalities be characterised by being non-excludable and non-rivalrous. In other words, individuals cannot (easily) be excluded from its impact, and impact to one individual does not reduce impact to others. Obviously, insofar as emissions will be fully charged to those that have caused them, e.g. in the case of greenhouse gases by the EU Emissions Trading System (EU ETS), such emissions will no longer be external to their source because they are then internalised in the plant-level costs.
Next to the above external effects, a last category of externalities can be distinguished, which has a more generic societal impact in common, and therefore typically is harder to quantify, namely the macro-economic and geo-political costs. These effects, while highly important from an overall national political welfare perspective, typically relate to the technologies’ impact on overall employment, national or regional competitiveness and innovation level, the geo-political implications including energy import dependence,

security of supply, etc. The distinction between these four categories of costs has been summarised in Figure 18, adapted from (Samadi, 2017).

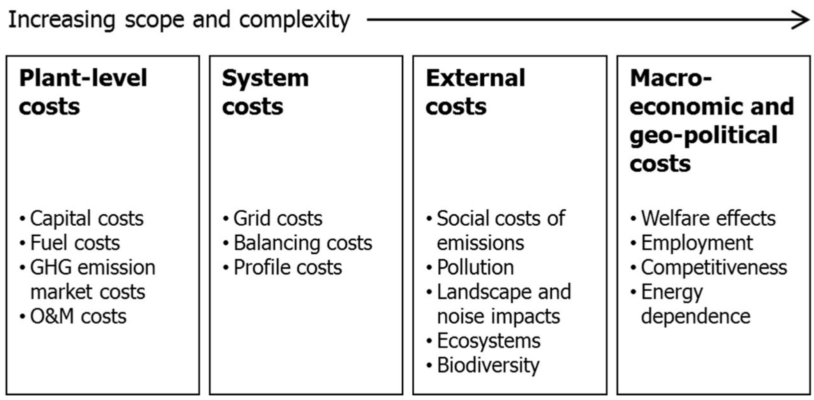

Figure 18. Main cost categories differentiated when determining the total social costs of energy technologies or projects.

Obviously, the issue whether a specific technology deserves to be further developed needs ideally to be addressed by assessment including all the four cost (and benefit) components, and compared to alternatives that are subjected to a similar assessment. The organisation of society, however, is not such that this will always happen, the result being that technologies that are optimal from a broader societal perspective will not come off the ground because these investment decisions are based on plant-level costs only. Such a negative result will typically apply if the system costs and externalities on the whole turn out to be relatively favourable. Although in theory this problem could be resolved by internalising, through specific dedicated policies and measures, the externalities into the plant-level costs and returns, the policy system is often not well-developed enough or acts too slowly to prevent the plant-level costs (and benefits) to differ from the broader society costs (and benefits). It seems fair to assume that the faster a societal problem develops, the bigger is the risk that costs will not be internalised. The energy transition may be a typical example of an issue that would strongly benefit from internalising costs, but where governments on average fail to timely charge the sources of those costs accordingly.

Hydrogen through power-to-gas technologies

In assessing the cost effectiveness of (offshore) power-to-gas technology, operators will, as was argued already, typically look at their plant-level costs and returns. To the degree that operators cover a wider scope of the value chain, e.g. because they also own transport or storage capacity, more of the system costs will be included in the calculus, but this is mostly not the case. Typical examples of a cost assessment and business case analysis of power-to-gas technologies (including the concept of methanation) in this tradition are (Van Leeuwen C. &., 2018) and (Van Leeuwen C. , 2018) concluding (p. 17): “It is important to note that even under [relatively optimistic] circumstances […] both the methane and hydrogen production prices are still higher than the revenues of the gases. For a positive NPV these revenues should become higher.” To put these key findings in its simplest way, if assessed with plan-level costs and returns only, it is hard to currently find a satisfactory business case for investing in an electrolyser to turn carbon free power into carbon free hydrogen, and a fortiori to take the additional step of hydrogen methanation. Various sensitivity analyses have meanwhile been carried out to see under what combination of (future) factors an acceptable business case can be reached for power-to-gas by, for instance, assuming much lower CAPEX levels for the electrolysers and related equipment; by assuming lower electricity price levels; or assuming higher prices for carbon free hydrogen. Some studies using this approach ((Jepma C. , 2015), (WEC, 2018), (DNVGL, Hydrogen in the electricity value chain, 2019) have concluded that even if only the direct costs are considered under a set of optimistic scenarios, production costs of carbon free hydrogen can get smaller than those of fossil hydrogen by 2030 (low carbon hydrogen) or 2035 (high carbon hydrogen).[26]

[26] This conclusion was reached based on the combination of the following assumptions: cost of natural gas raises from about €7/GJ in 2020 to about €9/GJ in 2050; CAPEX electrolyser declines from €800-1100/kWe in 2020 to about €500-700/kWe in 2050 [note that much lower – €200-300/kWe – figures are mentioned in industry]; renewable electricity prices decline from about €29/MWh average to almost €0/MWh during some 3000 hours per year (assumed running time electrolyser); and carbon costs per kg of grey hydrogen raise from about €0.06/kg in 2020 to >€0.50/kg in 2050 (DNV GL, 2019; chapter 3).

Only a few studies assessing the feasibility of power-to-gas technologies have so-far taken a broader perspective than plant-level costs and returns only by also including elements of the system costs and benefits or externalities into account, in order to assess on the basis of a (partial) social cost-benefit analysis whether power-to-gas is a feasible, if not indispensable, technology of the future in which the energy transition has anyhow to take place given global climate concerns. *A typical characteristic of all these studies is that none of them seems to have covered all system costs and externalities in the overall social cost-benefit assessment*, *but rather have zoomed in on some of these cost elements.* Examples are NSE 3 D1.2 that incorporates transport system costs; (Liao, 2018) who typically focused on environmental life-cycle aspects; (Van der Welle, 2018) focussing on energy mix diversification and energy security; and (Blanco, 2018) focussing on the energy system flexibility costs and benefits. Similar examples related to offshore power-to-gas are (Jepma C. &., 2017) (Jepma C. e., 2018), where the broader implications for the transport of energy produced offshore are included in the feasibility assessment of using offshore platforms as locations for converting offshore wind power into hydrogen. In this case it was concluded that if all wind power would be converted, this “technology turned out to be highly beneficial under the assumption that the savings on electricity grid investment that otherwise would need to have been made are taken into account in the NPV calculus (impact on the ‘carbon free’ hydrogen production costs about € 1.50 per kg)” (Jepma C. e., 2018, p. 5). So, on the whole, the feasibility results turned out to be much more positive for power-to-gas (relative to other technology options such as electrification or maintaining the status quo) for cases in which components of system costs and/or externalities had been included, as compared to analyses using the private costs and benefits only. In other words, disregarding system components and externalities creates a negative bias towards the societal benefits of enhancing power-to-gas technology (and equally towards various other sustainable energy technologies). Obviously, ideally an integrated assessment would be carried out *involving all cost components.* Such an analysis does not exist, however. Even modelling efforts that try to cast power-to-gas technologies in a wider modelling structure covering the overall energy system, such as ExternE[27] and TIMES[28], suffer from the fact that only some of the cost aspects, notably environmental impacts or energy security issues, are included in the analysis. Obviously, the issue that some externalities are very difficult to monetize will remain an obstacle to including externalities.

The ‘valley-of-death’ obstacle

A common characteristic of the evolvement of new technology is that it passes a number of stages before reaching maturity, i.e. a technology readiness level (TRL) at which the technology can be considered commercially feasible. Typical components of the technology development cycle are: the laboratory stage, the pilot stage, and the demonstration stage. During these stages, experience is gained with the technology such that costs will decline towards a maturity level. Such costs decline due to: *learning* (removing inefficiencies and the impact of economies of scale, as more devices can be produced and installed which reduces their cost price among others because fixed costs are divided over more units), due to *upscaling* (larger devices lead to cheaper production costs per unit of output), and sometimes due to more *international competition* (e.g. competition from low-wage regions reduces monopoly margins that existed in earlier stages). All in all, costs can come down considerably, sometimes in a limited period of time.

As far as the learning rate is concerned (which is still disregarding the impact of upscaling and more competition), Figure 19 may serve to illustrate that the impact of learning can be impressive indeed when it comes to carbon free energy technologies. The figure illustrates that, although the annual learning rate commonly shows a wide variation, the average rate for new energy technologies ranges between about 10 and 20% (median 13%).

Learning curves for electrolyser systems have been projected by way of illustration in Figure 20; although in the NSE study somewhat other long-term CAPEX data (€700/kW for PEM 2030 and €400/kW in 2040) has been used, they are in line with these figures derived from recent literature. The underlying calculated learning rates all show a slightly declining trend towards 2050, but range between 16.8% (2017) and 12% (2050) for PEM electrolysers; between 13.1% and 11% for alkaline electrolysers; and between 15.6% and 11.2% for solid oxide electrolysers.

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[27] http://www.externe.info
[28] https://iea-etsap.org/index.php/etsap-tools/model-generators/times

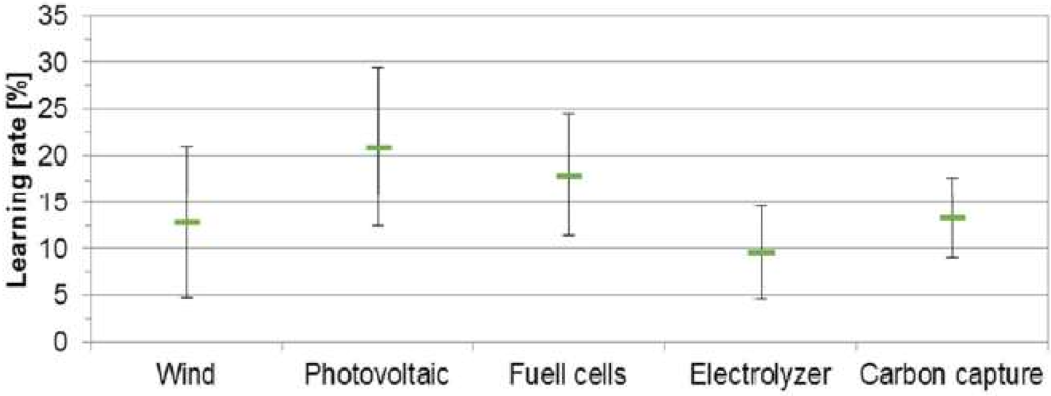

Figure 19. Overview of the mean learning rates of the considered technologies (Böhm, 2018, p. 36)

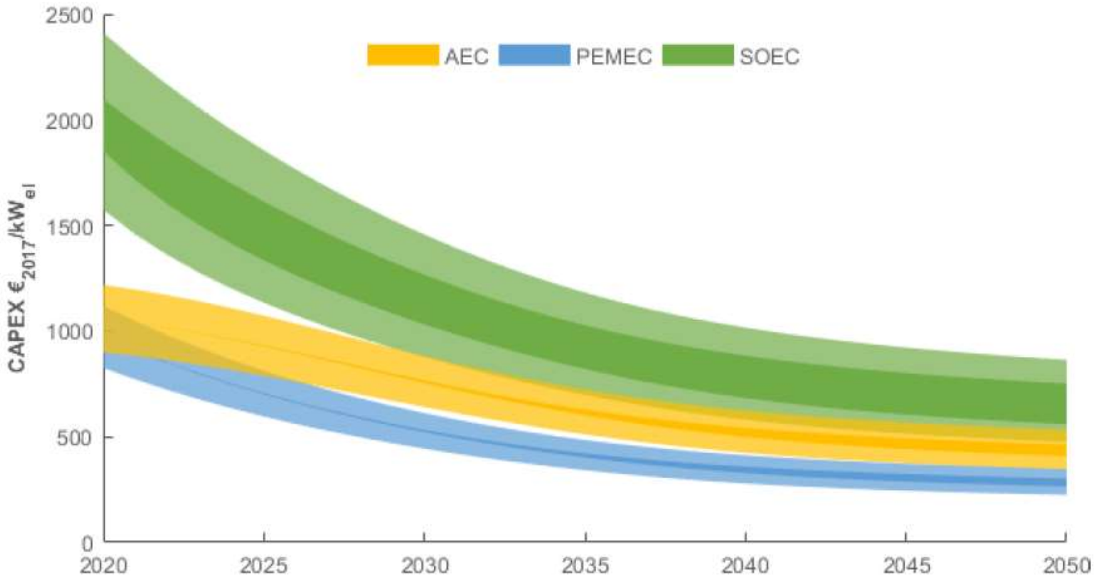

Figure 20. Resulting learning curves for electrolysis systems with an uncertainty of ±15 % on initial CAPEX (light-coloured areas) (Böhm, 2018, p. 109)

What are the implications of such massive learning for the cost of 5MW electrolysers per kW capacity? This is shown in the above figure: between 2017 and 2030 the costs have come down by roughly half; something similar is expected to happen in the period between 2030 and 2050. As was argued before, the above data only reflect the impact of learning on costs, not of upscaling or enhanced international competition. In actual practice therefore electrolyser costs will come down more and probably faster than projected in the above table. First, much larger electrolyser units will be introduced up to electrolysers at GW scale, and second if carbon free hydrogen develops into a substantial part of the energy system of the future, the number of producers of electrolysers will obviously grow considerably and with it the degree of international competition. In fact, now already per kW capacity electrolyser prices are mentioned in industry for much larger units in the order of €200-300.

Some evidence on what to expect from upscaling electrolyser technology from traditionally small-scale units towards units of 100 MW is shown in Figure 21, which relates to PEM electrolysers (Zauner, 2019). It shows that – next to the learning effect mentioned above – in addition upscaling may again reduce costs substantially by about a quarter to a third. To what extent enhanced international competition may further add to this price reduction is a matter of speculation in the absence of research on this.

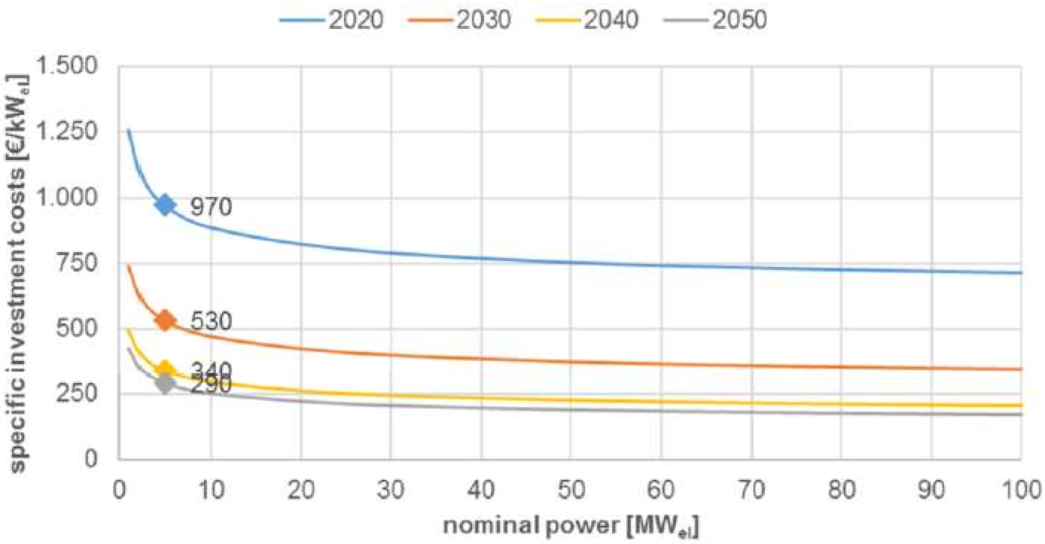

Figure 21. Specific investment costs of PEM electrolyser systems due to economies of scale for a nominal power of 1-100 MW in 2020, 2030, 2040, and 2050 (Zauner, 2019, p. 17)

Given the crucial role of electrolysers in power-to-gas technology development, and given the substantial scope for its cost reduction as illustrated above, it is clear that first movers in the power-to-gas technologies will face relatively high CAPEX levels compared to players that enter the market in a later stage. Together with the other risks related to producing carbon free hydrogen with the help of electrolysis, namely uncertainty about the future power prices (input) as well as about future returns (output) on the sales of the carbon free hydrogen (and possibly carbon free oxygen), this may scare off investors to step in, and inspire them to rather take a wait-and-see position. This disincentive to act as a frontrunner causes the 'valley-of-death' where a technology, promising as it may be on the longer term, yet will not get off the ground.

Another factor explaining the 'valley-of-death' phenomenon is the logical stages of technology development, usually indicated on the basis of so-called technology readiness levels (TRLs). Technology development usually starts from academic and laboratory stage (TRLs 1-4) via pilot (TRL 5) towards demonstration stages (TRL 6), the last one being the precursor of a system prototype (TRL 7) and towards market maturity (TRLs 8-9). Laboratory experiments on average are typically not extremely costly and are often part or offspring of publicly-funded fundamental research. This implies that there is an innovation gap when it comes to the TRL levels 4-6. Pilots (TRL 5) on average represent a larger investment, but usually several millions of euros will be enough to set up a decent testing facility. Major industries on the whole may be willing to engage in pilots because of the acceptable amount of resources it requires, especially if carried out in public-private consortia, but without sufficient support even pilots are often difficult to get off the ground. Funding demonstration sites typically requires much larger amounts (in the hundreds of millions), which may explain why, without significant public support, private industries will be reluctant to take the risks.

Although the hydrogen-related technology is in considerable development during the last years, the figure below, which has been published by 2014 (Institute, 2014) still may be a nice illustration of the 'valley-of-death' concept and in particular how the various sub-technologies related to the hydrogen cycle could be positioned on the learning curve. To get through such a 'valley-of-death' therefore requires a clear and convincing set of incentives from the public authorities, persuading the market that the technology will be part of the future under all policy and market regimes. In the absence of such a clear picture, the three effects mentioned above – learning, upscaling, and enhancing competition – will also not materialise and therefore the significant reductions in costs of the technology not achieved.

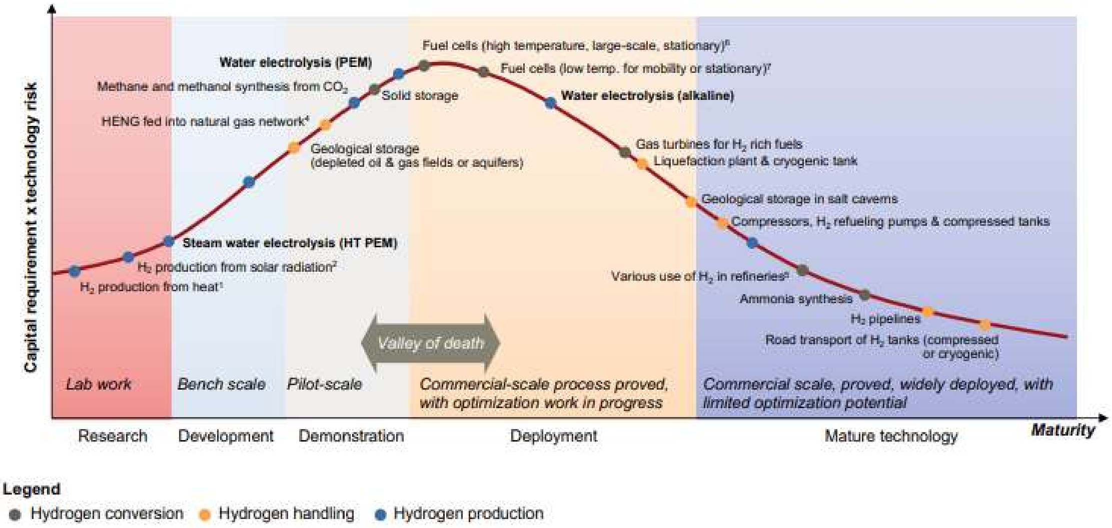

Figure 22. Commercial maturity curve of integrated hydrogen project by Ongeldige bron opgegeven.

Dysfunctional markets

Market imperfection may imply that there is *no full disclosure or transparency* about the product qualities and prices offered at the market. Also, high *barriers to enter or exit the market* may lead to market imperfection, such that for instance specific market players can strategically influence the market conditions. Finally, markets may be imperfect because they are *not sufficiently liquid*, which means that buyers and sellers will not find each other automatically, at least not without major costs.

The current market for hydrogen, which is typically dominated by high carbon hydrogen, can be considered imperfect for all the three reasons mentioned: no full disclosure or transparency; barriers to enter or exit the market; and insufficiently liquid markets.

First, most of the hydrogen is currently produced by a limited number of producers, such that hardly any public records exist on the actual price levels of hydrogen for industrial use. Moreover, most of the hydrogen consumed in industry is produced with on-site SMR (Fraile, 2015), so that these volumes almost by definition will be consumed against cost price without any necessity of price disclosure. The same applies to the lower purity-level hydrogen generated as a by-product from the production of chlorine. Therefore, only a small share of hydrogen produced in the EU28 is sold on commercial hydrogen markets (Fraile, 2015, p. 12).

In fact, most of the hydrogen transactions occur via bilateral contracts between two industries (Fraile, 2015). The hydrogen price may therefore differ significantly for similar industries. The inexistence of a global price database for hydrogen causes a lack of traceable and comparable information. Moreover, the price depends significantly on: the buyers' location; the state of delivery (liquid or gaseous); and the purity level.

Second, the hydrogen production in Europe is led by a few large industrial players dominating the market and setting the prices for hydrogen (Fraile, 2015). This causes market information to be asymmetric: one party knows more than the other. This may lead to opportunistic behaviour in which one party exploits the fact that the other party is less informed, potentially leading to adverse selection and moral hazard. An example relates to the quality of the hydrogen. If potential buyers do not exactly know the quality and/or origin of the hydrogen, some sellers may try to sell worse quality for the price of better-quality hydrogen. On the whole, the government has relatively little possibility to force suppliers to enter the market. however, permits and licenses may affect the number of firms at the market. Also, easing conditions to have access to finance may contribute to getting newcomers to the market.

Third, in the absence of a mature hydrogen market, prices for hydrogen that are collected on the basis of scattered information and circumstantial evidence, show a wide variety. Ruth, et al. (2019) show for instance that on the American market willingness to pay ranges between more than 3 dollars per kg for refining and ammonia to less than 1 dollar for injection into the national gas stream and some electric storage. Also, purity levels have a substantial impact on prices of the commodity (Ruth, 2019). Long-run price elasticities are equally unclear so far, as can be illustrated with the help of Figure 23. The figure illustrates how demand may react on changes in the hydrogen price level depending on which hydrogen scenario is used, including the scenario developed by (Gigler, 2018) in orange. Appendix: Hydrogen demand described the process and key-data that are used as inputs for this graph.

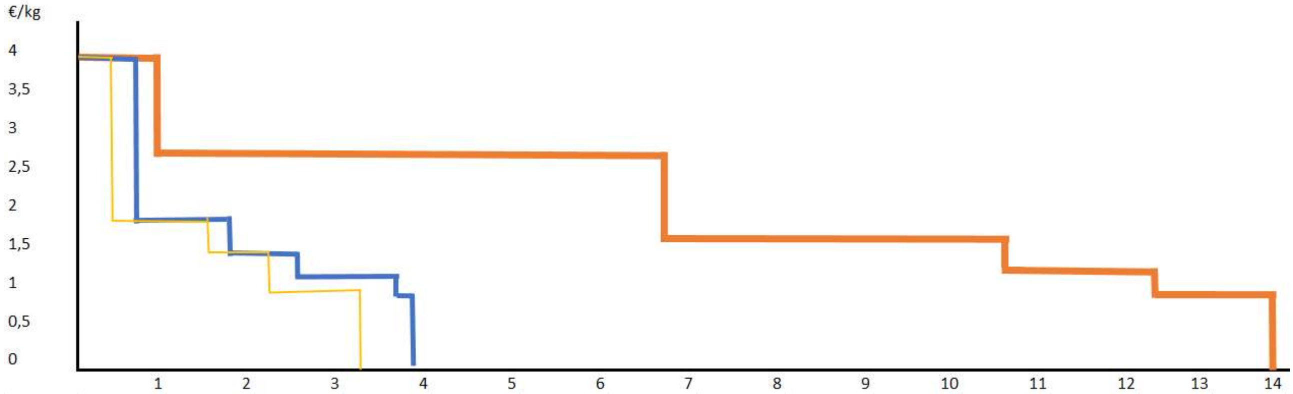

Figure 23. Potential hydrogen demand curves in 2050. Orange = scenario from 'hydrogen roadmap'; Blue = scenario NSE -- National Management; Yellow = scenario NSE - Regional Management

Information asymmetry can be reduced by government policies trying to enhance the equalisation of information. A common platform with transparent insight in the quality and/or origin of the produced and offered hydrogen could play an important role in overcoming adverse selection. It also helps when publicly supported standards and certification schemes inexpensively and completely inform consumers about the relative quality of all hydrogen available on the market.
Another obstacle to get to a mature hydrogen market is the absence of certification schemes or standards to clearly distinguish between carbon free, low carbon, and high carbon hydrogen. Also, the fact that rules and regulations with respect to hydrogen transport systems have not yet been worked out so far can act as a factor contributing to market immaturity. Existing hydrogen production infrastructure is, for instance, not subject to the provisions in the Gas Act governing unbundling, TPA, and tariff regulation. Practically, this means that access to networks is based on negotiations with the network operator and that it is up to the network operator to set the tariffs for the use of its network.

Having discussed the various market failures that may prevent power-to-gas technologies to get off the ground to its socially optimal size, scope, and timing, the logical next question arises what policies and measures can be initiated to address the various types of market failure.

Policy options to deal with market failures

As far as the first market failure, externalities and system costs, is concerned, it is important to internalise the externalities such that the private investor includes the external factors into the business calculation. The system outcomes (previous chapters) show that the re-use of existing offshore infrastructure is preferable from a social-economic point by 2030. The outcomes are in line with findings by other studies, on the whole suggesting that an all-electric system will face much higher societal costs than a system that keeps using the existing gas infrastructure[29]. Though, it is unlikely that offshore conversion will take off, if left to the market completely, as the plant-level costs for offshore conversion (the basis for decision making by investors) outweigh the plant-level costs for onshore conversion. Whether offshore conversion will arise, depends for a great extent on the potential of the Dutch government to internalise the externalities (system) costs, such that investors will not base their decisions on plant-level costs solely. This foremost requires insight in the system costs of private investments. This, however, in practice is even more complex than dealing with the common externalities, because system costs are mostly dealing with infrastructure issues related to transport and storage, and with the investments that are linked to the application of specific types of energy (e.g. adjusting a natural gas-based transmission system into an hydrogen based transmission system). Much of the infrastructure is quite often owned and controlled by state companies with regulated tariffs and, in order to provide for full competition between energy traders, as open access as possible. The regulation of tariffs often boils down to socialising rates, which means that some users of the grid benefit from a relatively low rate if the grid is little used, whereas other users may pay a relatively high rate for intensively-used parts of the grid. There is no clear guidance as to how such implicit taxation and subsidies should be employed in order to internalise these effects. Social welfare criteria could in fact indicate that this would not be necessary at all. This changes, however, if there are different energy system options with different social cost profiles, while in both cases transport and storage is controlled by the government. In such a case, investors initiating activities in the relatively low-cost energy system may indirectly require less costly infrastructure and storage, than investors in the high-cost energy system alternative. To the investor, this different impact on public expenditures will not be felt, but for the tax payer this difference can be quite noticeable. A clear example is the difference between an energy system that is building on the existing natural gas infrastructure, but switches from natural to carbon free hydrogen on the one hand, versus an energy system in which much of the existing gas system is left idle to be replaced by a new electricity-driven system.

What does all this imply for internalising energy system costs in terms of policies and measures? This basically means that the externalities are monetised and for instance translated into a system of (Pigovian) taxes and subsidies such that internalisation results. An obvious answer is that investors should receive a bonus when saving money for the tax payers, for instance, offshore conversion may lead to savings the transmission of offshore energy to shore. So far, no policies and measures have been initiated to our knowledge to monetise this bonus and explicitly turn it into a positive incentive on behalf of the investors in conversion technology. At the same time, overly expensive extensions of the electricity grid should be discouraged. Because much of this investment is financed via the government, it is important that the tax payer is aware of such expenditure, e.g. by explicitly being notified as part of the energy bill. Equally, TSOs could be forced to systematically implement social CBA (cost benefit analysis) to justify their investment decisions.

Also other schemes may indirectly achieve the same outcome, such as appointing ownership rights or instead not to encounter damages to specific stakeholders (Coase theorem). Rethinking stakeholder roles with regard to power-to-gas as well as renewable gases in general can lead to a better integration of externalities. As far as power-to-gas is concerned, there is still “considerable market uncertainty, for instance, as to who is eligible to own and operate storage and conversion facilities such as power-to-gas plants – only merchant players, or gas network operators and/or electricity network operators as well? It can be helpful if the government supports the deployment of crucial (hydrogen) infrastructure including regulated tariffs for infrastructure services, third party access, and measures to prevent or combat artificial congestion. Governmental evolvement reduces uncertainty and can overcome substantial investment barriers, which would otherwise hinder crucial contributions required to underpin the success of the energy transition” (Bothe, 2019, p. 72). It is therefore important that European rules and regulation is developed as soon as possible to redress such uncertainties. Another policy measure that might to lead to better integration of externalities is the application of the emissions trading schemes. The problem with emissions trading schemes, however,

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[29] Bothe and Janssen (2019) compared an ‘electricity and gas infrastructure’ scenario with an ‘all-electric plus gas storage’ scenario, and found savings in the order of €100 to some €300 per capita per year for each country that has been assessed. Extrapolating these findings to a cumulative figure that would apply for the EU-28 plus Switzerland in total, led to the conclusion that approximately € 1.3 to 2.1 trillion could be saved between today and 2050 (Bothe, 2019, p. 40).

can be that the value of emission reductions will insufficiently represent the externality because such value cannot be controlled since they are left to the market. In short, internalising externalities will require comprehensive pricing mechanisms covering the externalities' social costs; if the externality is greenhouse gas emissions, it implies comprehensive carbon pricing to reflect climate effects properly.
The second market failure is the well-known 'valley-of-death' problem, which may paralyse the timely development of a technology that is otherwise superior from a social perspective. Because the 'valley-of-death' typically relates to earlier TRL levels (typically 4-6), there is a clear role for the government to actively support those stakeholders that are willing to be engaged in those TRL stages as first mover, but may expect to lose money from it. Because the public support for these stages by definition has a temporary character and is oversee able in scope, there is no reason for governments not to actively support industry in getting through this 'valley-of-death', if the technology is considered to be an indispensable part of the energy future. Because of the almost absence of greening energy molecules in the EU (unlike the considerable progress made already towards greening energy electrons), and because under almost all scenarios energy molecules will remain as the backbone of the overall future carbon free energy system of the EU, power-to-gas is almost certainly an indispensable part of a carbon free energy future, if only because there are virtually no alternatives to create carbon free energy molecules. This is why support for (offshore) pilots and demos to get power-to-gas through the 'valley-of-death' would rather need to be considered as a matter of policy urgency, than of governmental 'wait-and-see'.
The third and final market failure is the absence of a transparent, mature and full-grown market itself for e.g. hydrogen, hydrogen-related technology, and hydrogen applications. To the extent possible the government can be helpful in supporting the rapid development of a mature market for carbon free and low carbon hydrogen and derived products by establishing guaranteed certificates of origin that account for the carbon free value of the hydrogen. Also, governments can set standards and implement rules and regulations to enhance development of a liquid and transparent hydrogen market, and prevent collusion or monopoly power abuse on such markets in their early stages of development. Quality standards and clear rules as to what quality ranges can be accepted also can support hydrogen markets, next to platforms or electronic devices making information on prices and volumes available for everyone. Supporting interoperability of international systems and cross-border trade options further will enhance market transparency and liquidity, and with it the introduction of power-to-gas technologies.

Conclusions

In this report we discussed the impact of increasing volumes of offshore wind energy produced at the North Sea on the overall energy system including its infrastructure use. The following research questions were set:

- **What would be the strategic role of the North Sea area for hydrogen production and transport; and what are the required steps towards an effective offshore hydrogen production roll-out?**

- **What governance and intervention mechanisms are needed to overcome the identified economic distortions, both in system integration and the development of hydrogen markets?**

The study has developed a number of perspectives all portraying possible future North Sea energy systems. All perspectives foresee an important role for North Sea wind as an intermittent renewable source in achieving the climate targets of the Netherlands. The projected rapidly increasing share of intermittent sources of energy production asks for significantly more flexibility in order to guarantee the required grid balancing condition of the electricity grid to be fulfilled. This report started from the notion that hydrogen will very likely play an important role in the future energy (and carbon free feedstock) system not only by providing that flexibility, but also to fulfil the increasing need for carbon free molecules by various sectors. The NSE - National Management and NSE – Regional Management scenarios showed that the share of offshore wind converted into hydrogen for flexibility purposes will be in the range of 43% to 49%.
Current policy plans of the Netherlands' government suggest that for the period 2020-2030 one intends to predominantly install the planned 11.5GW offshore wind capacity with the help of an electric connection to shore. On this point the study concluded, based on two so-called hybrid scenarios, i.e. allowing wind energy to be transported to shore either as electricity or as of hydrogen, that - at the current prices for carbon free hydrogen and without the investors capacity being reimbursed for public savings - there is not much evidence that offshore conversion will be an social-economically interesting option in the period before 2030. In fact, as was argued already, it is likely that the installation and maintenance of electrolysers systems offshore will lead to higher system costs than if those would have been installed onshore, such that it is uncertain if those extra costs would outweigh the grid savings. These results have been found both for the case in which pure hydrogen would be transported to shore, as well as for the cases in which the hydrogen would be admixed and subsequently separated again during its transport with the help of the gas grid. The system outcomes for the post 2030 period turned out to be quite different from those for the 2020-2030 period. For the period 2030-2050, at least some additional 10 to 20 GW offshore wind capacity will need to be installed per decade to realise the Dutch climate ambitions. Based on our NSE – Net van de Toekomst scenarios, this rapid increase in offshore wind results in the need for more flexibility and a higher conversion share (some 43% to 49%) of offshore wind into hydrogen in this period. The simulations indicated that, while considering an offshore cost factor of 175%, offshore hydrogen production does generates a more positive social-economic return in comparison to onshore hydrogen production in the post 2030 period. The concept of creating offshore energy conversion islands – that obviously could provide many other energy and non-energy functions as well – turns out to be the most feasible option. The main conditions for these investments to generate a positive business case are if sufficient economics of scale can be generated, so if wind capacities are sizeable enough, and whether there is sufficient distance from shore such that grid savings become substantial enough. We found for the post 2030 period that for higher wind farm capacities in the order of 6 GW, energy islands become economically very favourable, the more so as they are located further (more than 100 km) from shore. However, if (sandy) island construction would not be feasible due to for instance nature conservations, than existing platforms located further offshore (e.g. >120km) can be considered to be interesting potential locations for hybrid offshore hydrogen production. Between 2040 and 2050 the location of newly constructed wind farms is projected to be far-offshore. That far away from shore existing gas grids are on the whole relatively scarce so that mostly new pipelines will be required to transport the energy molecules to the market. It should be mentioned in this regard that a potential positive externality of developing new offshore hydrogen transport infrastructure is that it enables the competitive exploitation of proven gas reserves that otherwise would not have been economically feasible to explore. The option of combining conversion with a admixing the hydrogen to the natural gas is problematic on the longer term. A main reason is linked to the assumption that admixing rates will remain technically restrained to e.g. some 15% only. Under such a regime the flow of hydrogen is simply too low to get to an economically feasible result. Dedicated hydrogen production, so converting all wind power into hydrogen so that an electricity grid connection between the offshore wind farm and shore is no longer needed, on the whole, shows a greater

preference for offshore conversion configurations. This is logical because grid savings will be larger and overall the system is simpler, although less flexible, than the cost for the onshore system are slightly higher. This explains for instance also the finding that re-use of existing platforms for dedicated hydrogen production already generates positive returns if located at shorter distance from shore than comparable hybrid cases.

What does all this mean for policies and measures needed to proceed? For the specific situation of the North Sea offshore energy system, it is clear that without a serious and balanced set of policies and measures, much of the North Sea energy activity will not come off the ground, much later off the ground, or will develop in a way that is suboptimal from the social welfare perspective. Specific policies and measures that therefore seem to be in order, except from the more generic ones dealing with externalities mentioned above, are first of all to make sure that operators and investors in offshore wind power conversion (to hydrogen) are supported in the initial stages which can be characterised currently as a valley-of-death. In order for offshore conversion, probably starting on gas and later on followed by artificial islands, to get off the ground in time, operators that take the lead by setting up early initiatives would need to be supported via dedicated support schemes for pilots and demonstration projects, such that in the course of the next decade the knowledge base for offshore conversion is developed well enough to take advantage from the subsequent business case and societal positive impact. A fortunate point in this regard is that so far some 900MW offshore wind capacity to be installed by 2030 has not yet been assigned to a particular location. This capacity could be used for experimenting with offshore conversion options / flexibility technologies at the various locations mentioned. These demonstrations could simultaneously be developed as offshore demonstration sites so that one can benefit from the differences in site-specific conditions to enhance learning results. In line with this, governmental support could be provided in various ways, e.g. through tender conditions, specific support schemes for offshore conversion, support in platform adjustment, fiscal measures, etc. All such measures would, however, have in common that the next decade this technology becomes well-developed, and the operators ready to offshore conversion at significant scale from about 2030 onwards. The latter is necessary since congestion challenges in the electricity grid as well as costs to try to deal with them, will become a serious problem by 2030. The TSO TenneT indicated at several instances that congestion problems can become serious already before the 11.5GW projected offshore wind capacity is installed. Based on public cost considerations, congestion threats, and general resistance against new electricity grid infrastructure investment, public and political pressure in favour of offshore conversion may therefore build up before 2030. Next to this, probably dedicated measures will be required to enable a smooth operation of the hydrogen transport from the offshore conversion points to shore. As was argued before, this can be done via admixing the hydrogen with an ongoing natural gas flow through the existing gas infrastructure up to cases in which a new dedicated hydrogen infrastructure will be installed to connect the conversion point with shore, and to prevent the costly separation process that would be needed to get to pure hydrogen levels. It is important that such infrastructure options will be timely available and that issues such as licenses, ownership, responsibility, risk and safety management, and environmental issues can be operated smoothly. Due to the lack of experience with offshore transport of hydrogen, it is likely to be a relatively complex set of policies, measures, and regulations that will need to be set up to make the transport system work, and work in time.
Hydrogen will eventually need to be put on the market, which may have implications for standards and norms with respect to gas quality, pressure, etc., which in its turn may have implications for the quality of the gas infrastructure facilities and related equipment. All this may require rules and regulations related to quality, pressure, flow speed, corrosion, etc., which all will have to be taken care of, especially insofar as the saline environment will have an impact on such standards and norms.
Given the usual lead times required for preparing the significant investments for offshore infrastructure, such as islands, it is important that all the legal and regulatory issues that may emerge are addressed well in advance. The complexity of the North Sea is its multitude of economic activity, marine traffic, fisheries, ecological activities, military activity, energy activity, etc., so that introducing a number of artificial islands, next to the multitude of new wind turbines, will raise issues how this is to be combined with all the other activities going on in the ever fuller North Sea. Although it is not necessarily true that creating new islands in the Netherlands' continental shelf of the North Sea is a legal nightmare by definition, it is clear that the legal complexity can be enormous and not only because the phenomenon of an artificial island in the North Sea is an unprecedented case anyhow. An example of the complexities that may arise relate to the fact that islands in the exclusive economic zone fall outside the territorial waters of a nation, so that other countries may feel a reason to interfere. Creating new islands in the North Sea therefore requires international coordination, for which bodies and authorities not always exist (yet). Sorting out how an effective and sufficiently internationally accepted solution can be found will obviously take considerable time and therefore will need to be initiated long before the actual energy islands are projected to be built.

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Appendix

Appendix: Model input alternative

Conversion to hydrogen	2030	2040	2050	Source/assumption
E-demand	0.49	0.81	1.2	NvdT – National Management for 2050. Expect proportional increase until 2050.
E-supply (solar)	0.05	0.09	0.12	NvdT – National Management for 2050. Expect proportional increase until 2050.
E-supply (wind onshore)	0.06	0.10	0.15	NvdT – National Management for 2050. Expect proportional increase until 2050. Expected load factor of 34%
E-supply (wind offshore	0.19	0.58	0.98	PBL - Sustainable together. Expected to load factor of 52%. Expect proportional increase until 2050. 2030 is set to 11.5GW.
E-supply (bio-based/import/fossil based)	0.19	0.04	0	Left over after subtraction supply from demand
H2-demand	0.30	0.60	0.88	High demand scenario Workgroup H2 climate agreement.
H2-hybrid supply	0.11	0.27	0.44	NvdT – National Management for 2050. Expect proportional increase until 2050
H2-hybrid supply (wind offshore)	0.07	0.21	0.35	Based on share offshore wind in total installed intermittent renewable capacity, which is 78% for 2050.
H2-hybrid supply (other intermittent)	0.04	0.06	0.09	Total H2 hybrid supply minus H2-hybrid supply from wind offshore
E-supply to H2 (offshore wind)	0.09	0.28	0.46	Input from hybrid supply from offshore wind divided by efficiency of 75%
Share wind to be converted	**47%**	**47%**	**47%**	**E-supply for H2 (from offshore wind) divided by total E-supply from offshore wind.**

Table 16: Model input hybrid hydrogen in 2050 in Alternative I

Conversion to hydrogen	2030	2040	2050	Source/assumption
E-demand	0.06	0.11	0.22	NvdT – Regional Management for 2050. Expect proportional increase until 2050.
E-supply (solar)	0.13	0.21	0.3	NvdT – Regional Management for 2050. Expect proportional increase until 2050.
E-supply (wind onshore)	0.07	0.12	0.17	NvdT – Regional Management for 2050. Expect proportional increase until 2050. Expected load factor of 34%
E-supply (wind offshore	0.19	0.35	0.52	NvdT – Regional Management for 2050. Expected to load factor of 52%. Expect proportional increase until 2050. 2030 is set to 11.5GW.
E-supply (bio-based/import/fossil based)	0	0	0	Left over after subtraction supply from demand
H2-demand	0.30	0.60	0.88	High demand scenario Workgroup H2 climate agreement.
H2-supply for flexibility	0.11	0.20	0.29	NvdT – Regional Management for 2050 Expect proportional increase until 2050
H2-supply (wind offshore)	0.05	0.10	0.15	Based on share offshore wind in total installed intermittent renewable capacity, which is 48% for 2050.
H2-supply (other intermittent)	0.06	0.10	0.14	Total H2 hybrid supply minus H2-hybrid supply from wind offshore
E-supply to H2 (offshore wind)	0.07	0.14	0.20	Input from hybrid supply from offshore wind divided by efficiency of 75%
Share wind to be converted	**39%**	**39%**	**39%**	**E-supply for H2 (from offshore wind) divided by total E-supply**

Table 17: Model input hybrid hydrogen in 2050 in Alternative II

Appendix: Methodology cost component

Capex platform

The structure cost for offshore platforms follows the methodology of DNV GL 2018. The following reasoning, which is in line with the used methodology by DNVGL, 2018:

- P2H2 steelwork mass (tonnes) = 1.035 * equipment mass (tonnes)
- P2H2 Topside Electrical Equipment Mass = 5.65 * Power (MW)
- P2H2 Auxiliary Equipment, gratings, cladding and control room mass (tonnes) = 1.1689 * electrical equipment mass
- P2H2 Topside Processing Plant Equipment Mass = 5.65 * Power (MW)
- P2H2 Topside Cooling Equipment Mass = 1.5 * Power (MW)
- P2H2 Topside Volume (m3) = Power (MW) * 193.55
- • Topside Coating Area (m2) = 12.74* (Steel Mass (tonnes) + Aux. Equipment (rooms and cladding) mass (tonnes))
- Grating area (m2) = 0.11 * volume (m3)
- Jacket Mass per unit water depth (tonnes / meter water depth) = 0.018225 * topside mass (tonnes) - 15.792785. We assumed a water depth of 30m.
- Jacket Anode mass = 0.0095 * jacket mass + 7.5265
- Jacket Coating Area = 1.0662 * jacket mass + 597.33
- Jacket Secondary steel mass is based on experience, water depth and number of boat landings and j-tubes/pipes.
- Pile length is based on the compressive resistance of dead load per pile * 2 (to account for live loading). Assumed skin friction of 40kPa (0m to 20m depth, and 81kPa 20m+ depth. End bearing 4800kPa at 30m+ embedment.

We increased all assumptions on the above sizing with a factor two, due to the found under-estimation from a more detailed engineering design, as executed within D. 3.6. Applying this information has led to the tables below.

	P2H2-1	P2H2-2	P2H2-3	P2H2-4
Costs Cladding	€ 1.980.000	€ 9.906.000	€ 19.812.000	€ 39.627.000
Cost Steel	€ 9.275.000	€ 46.368.000	€ 92.736.000	€ 185.472.000
Cost Grating	€ 766.440	€ 3.832.200	€ 7.664.760	€ 14.969.160
Coating	€ 6.069.600	€ 30.347.520	€ 60.694.800	€ 121.389.840
Total cost topside	€ 18.091.040	€ 90.453.720	€ 180.907.560	€ 361.458.000

Table 18: Total cost topside based on Table 19 and Table 20

	Topside Rating (MW)	Est. Mass of Electric Eq. (T)	Est. Mass of Processing Plant (T)	Est. mass of cooling eq.	Est. Topside Volume	T. mass of h2 production plant	Est. mass of sup. Steel	Rooms & cladding	Grating m2	Est. coating area	Total Mass (T)
P2H2 1	100	565	565	150	36375	1280	2650	660	4.258	50580	4590
P2H2 2	500	2825	2825,00	750	181875	6400	13248	3302	21290	252896	22950
P2H2 3	1000	5650	5650	1500	363750	12800	26496	6604	42582	505790	45900
P2H2 4	2000	11300	11300	3000	727500	25600	52992	13209	83162	1011582	91801

Table 19: HVDC topside mass estimation based on DNVGL methodology incl. a size factor of 200%

Steel rate (Euro/te)	Cladding rate (Euro/te)	Grating rate (Euro/m2)	Coating rate (Euro/m2)
€ 3.500	€ 3.000	€ 180	€ 120

Table 20: Topside costing assumptions

Pile Mass and Structure	Topside Power Rating (MW)	Estimate Steelwork Te	Cost Pile
P2H2 1	100	1082	€ 2.164.000
P2H2 2	500	2916	€ 5.832.000
P2H2 3	1000	6468	€ 12.936.000
P2H2 4	2000	13004	€ 26.008.000

Table 21: support structure mass cost estimation based on DNVGL methodology incl. a size factor of 200%

Cost	P2H2-1	P2H2-2	P2H2-3	P2H2-4
Primary Rate (euro / te)	5244000	33812000	69516000	140924000
Secondary Rate (euro / Te)	455000	625000	790000	1580000
Anodes Rate (euro / te)	210830,75	1092867,75	2195228,75	4399950,75
Coating Rate (euro / m2)	407148,768	2234700,864	4518757,152	9086869,728
Total cost jacket mass	6316979,518	37764568,61	77019985,9	155990820,5

Table 22: Total cost jacket mass based on Table 23 and Table 24

Primary rate (euro/te)	€ 2.000
Secondary rate (euro/te)	€ 2.500
Anodes rate (euro/te)	€ 6.500
Coating rate (euro/te)	€ 120

Table 23: Jacket mass costing assumptions

Jacket Mass	Total Mass Estimation (tonnes)	Estimated Jacket Mass (tonnes)	Secondary Steel Estimation (tonnes)	Anode Estimations (tonnes)	Coating area estimation
P2H2 1	4590	2622	182	32,4355	3392,9064
P2H2 2	22950	16906	250	168,1335	18622,5072
P2H2 3	45900	34758	316	337,7275	37656,3096
P2H2 4	**91801**	**70462**	**632**	**676,9155**	**75723,9144**

Table 24: support jacket mass estimation based on DNVGL methodology incl. a size factor of 200%

Appendix: Methodology pipeline and compression

Capex pipeline

Model input pressure drop calculation	Value
Output pressure (on shore)	68 bar
Admissible surface roughness new pipeline (epsilon)	0.05 mm
Temperature (deg. C. at inlet)	10 deg. C
Molecular weight	2.016 g/mol
Dynamic viscosity (Pa.s)	0.0000086
Velocity (m/s)	Between 10 and 20 m/s.
Mass flow rate (kg/h)	Variable input (dependable on the scenario)
Distance	Variable input (dependable on the scenario)
(Internal) Diameter (m)	Variable output (dependable on the scenario)
Pressure (bar) at inlet	Variable output (dependable on the scenario)

Table 25: input parameters pressure drop calculation tool

The main defining parameters for the CAPEX of the pipeline are, next to the choice of material, the pipeline diameter and the distance that needs to be covered i.e. the total pipeline length (EBN, Gasunie, 2017). The pressure drop calculation tool (developed as part of WP 3.4[30]) is used to determine the diameter of the pipeline and the design or inlet pressure of the pipeline. A number of limitations were set to this tool (see Table 25: input parameters pressure drop calculation tool
).
The method to construct associated costs follows the series of estimations made by EBN and Gasunie in their report 'Transport en opslag van CO2 in Nederland' (EBN, Gasunie, 2017). It states that on average, besides the pipeline material, two major factors are crucial for pipeline investments costs: the diameter and the distance to be covered. Generally put, costs per kilometre decrease as the distance increases. The report estimates were based on market prices and globally realized projects; because market prices were quite low at the measurement moment (2017), the estimates are assumed to have accuracy ranges from -20 to +40%. Other factors that can have a prominent impact on the cost of laying new pipelines include: submarine obstacles (such as other pipes and cables), but also super-sea obstacles, such as platforms or wind farms. All this may require that crossings be implemented. As this study does not focus on a specific location within the North Sea, it is not possible to assess how many and what type of crossings should be considered when concrete locations will be studied. The CAPEX of pipelines with different diameters is shown in the Figure 24. It is important to mention that there are more costs related to the installation of pipelines which are not taken into account in this study due to undefined locations. To such costs belong e.g. pre-installation surveys and tests as well as the CAPEX of crossings. Moreover, the application of different material (poly-ethylene) might bring the costs for dedicated hydrogen pipelines down.

[30] This tool is available upon request to NSE

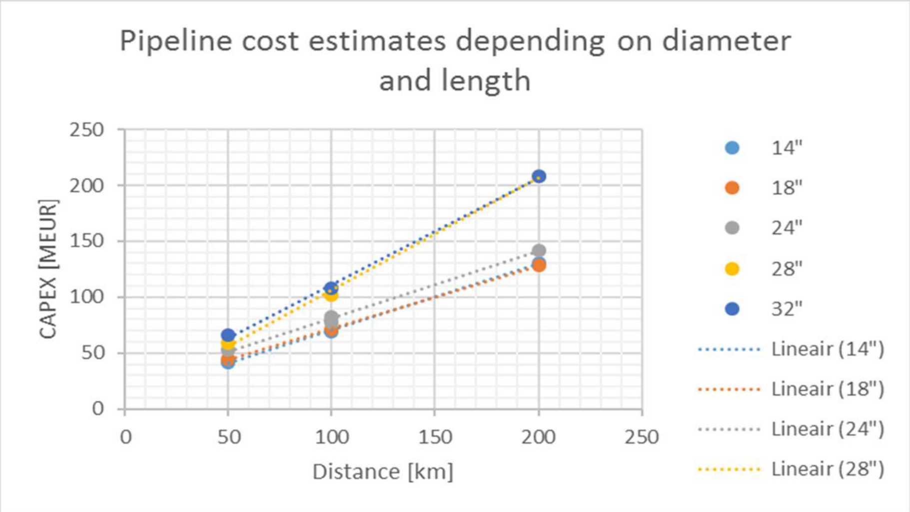

Figure 24: Pipeline cost estimates as a function of diameter and length (author's figure, based on (EBN, Gasunie, 2017))

Capex compression

In a number of scenario's offshore hydrogen compression is a necessity. The highest pressure is requested for ammonia production (some 250 bar), then for transport (some 50-60 bar) and ultimately also for the methanol process (some 50 bar). For each of the scenarios compression costs are included. For this purpose, a compression power, noted P in kW, is calculated determining together with the operating hours and the load profile the energy required for compression (Equation 1

$$P = \frac{Q}{3600 * 24 * 33.33} \times \frac{Z \times T \times R}{M_{H_2} \times \eta_{comp}} \times \frac{N_\gamma}{\gamma - 1} \times \left[\left(\frac{P_{out}}{P_{in}}\right)^{\frac{\gamma-1}{N_\gamma}} - 1\right]$$

Equation 2: compression power based on (Castello, 2005) & (Jean Andre, 2014).

Where:

- Q the flow rate (in kWh per day) by taking a low heating value (LHV) of 33.33 kWh/kg specific to hydrogen,
- P_{in} the inlet pressure of the compressor (suction),
- P_{out} the outlet pressure of the compressor (discharge),
- Z the hydrogen compressibility factor,
- N the number of compressor stages,
- T the inlet temperature of the compressor (278 K),
- γ the diatomic constant factor (1.4),
- M_{H2} the molecular mass of hydrogen (2.0158 g/mol),
- η_{comp} the compressor efficiency ratio (here taken as 75%),
- the universal constant of ideal gas R = 8.314 J K-1 mol-1.

The CAPEX of compression is determined on the base of compression power (P) required for the various scenarios. Capital costs of about €2,000/kW[31] are assumed, operational expenses of 2% of the initial capex p.a. and in addition, varying electricity costs based on compression power (P).

[31] Based on (Jean Andre, 2014) while assuming an exchange rate of 1.20 EUR/USD (2017)

Appendix: Assumption electric system cost based on TOET

Installed wind capacity in MW						220 KV AC CAPEX - hardware costs										Distance in km
	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	€ 366	€ 402	€ 438	€ 473	€ 509	€ 545	€ 582	€ 650	€ 689	€ 727	€ 766	€ 805	€ 844	€ 883	€ 1.085	€ 1.194
2000	€ 629	€ 690	€ 750	€ 811	€ 872	€ 933	€ 1.063	€ 1.195	€ 1.268	€ 1.340	€ 1.413	€ 1.486	€ 1.559	€ 1.633	€ 1.927	€ 2.012
3000	€ 937	€ 1.031	€ 1.126	€ 1.220	€ 1.315	€ 1.410	€ 1.505	€ 1.600	€ 1.695	€ 1.791	€ 2.061	€ 2.168	€ 2.275	€ 2.382	€ 2.712	€ 2.831
4000	€ 1.184	€ 1.301	€ 1.418	€ 1.535	€ 1.653	€ 1.770	€ 2.016	€ 2.145	€ 2.274	€ 2.404	€ 2.533	€ 2.849	€ 2.991	€ 3.133	€ 3.496	€ 3.650
5000	€ 1.432	€ 1.572	€ 1.793	€ 1.945	€ 2.096	€ 2.247	€ 2.399	€ 2.550	€ 2.853	€ 3.017	€ 3.181	€ 3.345	€ 3.707	€ 3.883	€ 4.280	€ 4.468
6000	€ 1.740	€ 1.913	€ 2.086	€ 2.260	€ 2.433	€ 2.607	€ 2.909	€ 3.095	€ 3.281	€ 3.467	€ 3.828	€ 4.026	€ 4.422	€ 4.633	€ 5.065	€ 5.287
7000	€ 1.988	€ 2.183	€ 2.379	€ 2.669	€ 2.876	€ 3.084	€ 3.292	€ 3.501	€ 3.860	€ 4.080	€ 4.301	€ 4.708	€ 4.940	€ 5.383	€ 5.849	€ 6.106
8000	€ 2.295	€ 2.525	€ 2.754	€ 2.984	€ 3.214	€ 3.444	€ 3.803	€ 4.045	€ 4.288	€ 4.694	€ 4.948	€ 5.389	€ 5.656	€ 6.133	€ 6.633	€ 7.158
9000	€ 2.543	€ 2.795	€ 3.047	€ 3.299	€ 3.657	€ 3.921	€ 4.186	€ 4.590	€ 4.867	€ 5.144	€ 5.596	€ 5.885	€ 6.372	€ 6.883	€ 7.418	€ 7.977
10000	€ 2.791	€ 3.065	€ 3.422	€ 3.708	€ 3.995	€ 4.282	€ 4.697	€ 4.996	€ 5.446	€ 5.757	€ 6.243	€ 6.566	€ 7.088	€ 7.633	€ 8.202	€ 8.795

Installed wind capacity in MW						320 KV DC CAPEX - hardware costs										Distance in km
	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	€ 998	€ 1.020	€ 1.043	€ 1.065	€ 1.088	€ 1.111	€ 1.133	€ 1.156	€ 1.179	€ 1.201	€ 1.224	€ 1.247	€ 1.269	€ 1.292	€ 1.314	€ 1.337
2000	€ 1.961	€ 2.004	€ 2.048	€ 2.092	€ 2.136	€ 2.180	€ 2.223	€ 2.267	€ 2.311	€ 2.355	€ 2.398	€ 2.442	€ 2.486	€ 2.530	€ 2.574	€ 2.617
3000	€ 2.924	€ 2.989	€ 3.054	€ 3.119	€ 3.183	€ 3.248	€ 3.313	€ 3.378	€ 3.443	€ 3.508	€ 3.573	€ 3.638	€ 3.703	€ 3.768	€ 3.833	€ 3.898
4000	€ 3.887	€ 3.973	€ 4.059	€ 4.145	€ 4.231	€ 4.317	€ 4.403	€ 4.489	€ 4.575	€ 4.662	€ 4.748	€ 4.834	€ 4.920	€ 5.006	€ 5.092	€ 5.178
5000	€ 4.850	€ 4.957	€ 5.064	€ 5.172	€ 5.279	€ 5.386	€ 5.493	€ 5.601	€ 5.708	€ 5.815	€ 5.922	€ 6.029	€ 6.137	€ 6.244	€ 6.351	€ 6.458
6000	€ 5.813	€ 5.941	€ 6.070	€ 6.198	€ 6.327	€ 6.455	€ 6.583	€ 6.712	€ 6.840	€ 6.968	€ 7.097	€ 7.225	€ 7.353	€ 7.482	€ 7.610	€ 7.738
7000	€ 6.776	€ 6.926	€ 7.075	€ 7.225	€ 7.374	€ 7.524	€ 7.673	€ 7.823	€ 7.972	€ 8.122	€ 8.271	€ 8.421	€ 8.570	€ 8.720	€ 8.869	€ 9.019
8000	€ 7.739	€ 7.910	€ 8.081	€ 8.251	€ 8.422	€ 8.593	€ 8.763	€ 8.934	€ 9.105	€ 9.275	€ 9.446	€ 9.617	€ 9.787	€ 9.958	€ 10.129	€ 10.299
9000	€ 8.702	€ 8.894	€ 9.086	€ 9.278	€ 9.470	€ 9.661	€ 9.853	€ 10.045	€ 10.237	€ 10.429	€ 10.620	€ 10.812	€ 11.004	€ 11.196	€ 11.388	€ 11.579
10000	€ 9.666	€ 9.878	€ 10.091	€ 10.304	€ 10.517	€ 10.730	€ 10.943	€ 11.156	€ 11.369	€ 11.582	€ 11.795	€ 12.008	€ 12.221	€ 12.434	€ 12.647	€ 12.860

Installed wind capacity in MW						525 KV DC CAPEX - hardware costs										Distance in km
	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	€ 843	€ 855	€ 867	€ 879	€ 891	€ 903	€ 916	€ 928	€ 940	€ 952	€ 964	€ 976	€ 989	€ 1.001	€ 1.013	€ 1.025
2000	€ 1.654	€ 1.677	€ 1.700	€ 1.723	€ 1.746	€ 1.769	€ 1.792	€ 1.815	€ 1.839	€ 1.862	€ 1.885	€ 1.908	€ 1.931	€ 1.954	€ 1.977	€ 2.000
3000	€ 2.479	€ 2.516	€ 2.553	€ 2.589	€ 2.626	€ 2.662	€ 2.699	€ 2.736	€ 2.772	€ 2.809	€ 2.845	€ 2.882	€ 2.919	€ 2.955	€ 2.992	€ 3.028
4000	€ 3.270	€ 3.313	€ 3.356	€ 3.399	€ 3.443	€ 3.486	€ 3.529	€ 3.572	€ 3.615	€ 3.659	€ 3.702	€ 3.745	€ 3.788	€ 3.831	€ 3.874	€ 3.918
5000	€ 4.066	€ 4.117	€ 4.168	€ 4.219	€ 4.270	€ 4.321	€ 4.372	€ 4.423	€ 4.474	€ 4.525	€ 4.576	€ 4.627	€ 4.677	€ 4.728	€ 4.779	€ 4.830
6000	€ 4.885	€ 4.949	€ 5.012	€ 5.075	€ 5.139	€ 5.202	€ 5.265	€ 5.329	€ 5.392	€ 5.455	€ 5.519	€ 5.582	€ 5.645	€ 5.709	€ 5.772	€ 5.835
7000	€ 5.701	€ 5.776	€ 5.851	€ 5.926	€ 6.001	€ 6.076	€ 6.151	€ 6.226	€ 6.301	€ 6.376	€ 6.451	€ 6.526	€ 6.601	€ 6.676	€ 6.751	€ 6.826
8000	€ 6.517	€ 6.603	€ 6.690	€ 6.777	€ 6.863	€ 6.950	€ 7.036	€ 7.123	€ 7.210	€ 7.296	€ 7.383	€ 7.470	€ 7.556	€ 7.643	€ 7.730	€ 7.816
9000	€ 7.336	€ 7.435	€ 7.534	€ 7.633	€ 7.732	€ 7.831	€ 7.930	€ 8.029	€ 8.128	€ 8.227	€ 8.326	€ 8.425	€ 8.524	€ 8.623	€ 8.722	€ 8.821
10000	€ 8.093	€ 8.192	€ 8.291	€ 8.390	€ 8.489	€ 8.588	€ 8.687	€ 8.786	€ 8.885	€ 8.984	€ 9.084	€ 9.183	€ 9.282	€ 9.381	€ 9.480	€ 9.579

Figure 25: total cost electric system based on TOET (D.3.8)

Installed wind capacity in MW						220 KV AC CAPEX - hardware costs offshore substation										Distance in km
	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	€ 86	€ 86	€ 87	€ 87	€ 87	€ 88	€ 88	€ 87	€ 87	€ 87	€ 87	€ 88	€ 88	€ 88	€ 98	€ 91
2000	€ 131	€ 131	€ 131	€ 131	€ 132	€ 132	€ 136	€ 133	€ 133	€ 134	€ 134	€ 135	€ 135	€ 136	€ 139	€ 139
3000	€ 176	€ 176	€ 177	€ 177	€ 177	€ 178	€ 178	€ 178	€ 179	€ 179	€ 181	€ 182	€ 183	€ 184	€ 187	€ 188
4000	€ 221	€ 221	€ 222	€ 222	€ 222	€ 223	€ 224	€ 225	€ 225	€ 226	€ 227	€ 229	€ 230	€ 231	€ 235	€ 236
5000	€ 266	€ 267	€ 267	€ 268	€ 268	€ 269	€ 269	€ 270	€ 272	€ 273	€ 274	€ 275	€ 278	€ 279	€ 283	€ 284
6000	€ 311	€ 312	€ 312	€ 313	€ 313	€ 314	€ 315	€ 316	€ 317	€ 318	€ 321	€ 322	€ 325	€ 327	€ 331	€ 333
7000	€ 356	€ 357	€ 375	€ 358	€ 359	€ 360	€ 361	€ 362	€ 364	€ 365	€ 366	€ 369	€ 371	€ 374	€ 379	€ 381
8000	€ 402	€ 402	€ 403	€ 404	€ 404	€ 405	€ 407	€ 408	€ 409	€ 412	€ 413	€ 416	€ 418	€ 422	€ 426	€ 431
9000	€ 447	€ 447	€ 448	€ 449	€ 450	€ 451	€ 452	€ 454	€ 456	€ 457	€ 460	€ 462	€ 466	€ 470	€ 474	€ 480
10000	€ 492	€ 493	€ 493	€ 494	€ 495	€ 496	€ 498	€ 500	€ 502	€ 504	€ 507	€ 509	€ 513	€ 518	€ 522	€ 528

Installed wind capacity in MW						320 KV DC CAPEX - hardware costs - offshore substation										Distance in km
	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500	€ 500
2000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000	€ 1.000
3000	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500	€ 1.500
4000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000
5000	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500	€ 2.500
6000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000	€ 3.000
7000	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500	€ 3.500
8000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000
9000	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500	€ 4.500
10000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000	€ 5.000

Installed wind capacity in MW						525 KV DC CAPEX - hardware costs offshore substation										Distance in km
	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
1000	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400	€ 400
2000	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800	€ 800
3000	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200	€ 1.200
4000	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600	€ 1.600
5000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000	€ 2.000
6000	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400	€ 2.400
7000	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800	€ 2.800
8000	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200	€ 3.200
9000	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600	€ 3.600
10000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000	€ 4.000

Figure 26: cost offshore substation based on TOET (D3.8)

Appendix: NSE - National Management

2020-2030				
G1	600	90		Onshore hybrid conversion
C	129	26		Onshore hybrid conversion
C	108	30		Onshore hybrid conversion
C	120	15		Onshore hybrid conversion
A	700	55		Onshore hybrid conversion
A	700	55		Onshore hybrid conversion
G1	700	95		Onshore hybrid conversion
C1	700	30		Onshore hybrid conversion
C2	1400	60		Onshore hybrid conversion
B1	700	32		Onshore hybrid conversion
B1	700	32		Onshore hybrid conversion
				Onshore hybrid conversion
C3	1000	110		
C3	1000	110		Onshore hybrid conversion
C3	1000	170		Onshore hybrid conversion
C3	1000	170		Onshore hybrid conversion
C3	400			Offshore hybrid innovation area
G1	150			Offshore hybrid innovation area
2030-2040				
B2	1.400	50		Onshore hybrid conversion
C4	1.400	50		Onshore hybrid conversion
B4	2000	60		Onshore hybrid conversion
B3	2.000	70		Onshore hybrid conversion
G2	1.400	70		Onshore hybrid conversion
G3	1.400	80		Onshore hybrid conversion
C5	2000	110		Offshore hybrid conversion island
D1	5.000	110		
G4	2000	130		Offshore hybrid conversion island
G5	2000	130		
D2	3000 (Alternative I)	110		Offshore dedicated island
2040-2050				
E1	5000	220		Offshore hybrid conversion area with new islands / existing platforms / new platforms
F1	4000	220		
F2	6000	230		
F3	6000	280		
F5	4000 (Alternative I)		230	Offshore dedicated island

Appendix: NSE - Regional Management

2020-2030					
G1		600		90	**Onshore hybrid conversion**
C		129		26	**Onshore hybrid conversion**
C		108		30	**Onshore hybrid conversion**
C		120		15	**Onshore hybrid conversion**
A		700		55	**Onshore hybrid conversion**
A		700		55	**Onshore hybrid conversion**
G1	700		95		**Onshore hybrid conversion**
C1		700		30	**Onshore hybrid conversion**
C2		1400		60	**Onshore hybrid conversion**
B1		700		32	**Onshore hybrid conversion**
B1		700		32	**Onshore hybrid conversion**
					Onshore hybrid conversion
C3		1000		110	
C3		1000		110	**Onshore hybrid conversion**
C3		1000		170	**Onshore hybrid conversion**
C3		1000		170	**Onshore hybrid conversion**
C3		400			**Offshore hybrid innovation area**
G1		150			**Offshore hybrid innovation area**
2030-2040					
B2	1.400			50	Onshore dedicated conversion
C4	1.400			50	Onshore dedicated conversion
D1	2000			110	Onshore dedicated conversion
G1	2000			130	Onshore dedicated conversion
G2	1000 (Alternative II)			130	Offshore dedicated island
D2	2000 (Alternative II)			110	Offshore dedicated island
2040-2050					
F1	3000		230		Offshore dedicated island
F2	2500			280	Offshore dedicated island
F3	1200 (Alternative II			280	Offshore dedicated island
F4	1700 (Alternative II)			230	Offshore dedicated island

Appendix: Hydrogen demand

The aggregated demand curve for potential future used of hydrogen by various end-users follows the approach set by (Ruth, 2019). The market potential for hydrogen in the NSE National Management and NSE Regional Management scenario are based on the NvdT-scenarios developed by (Afman, 2017) and compared to the theoretical (or maximum) market potential (Gigler, 2018). Figure 28 provides an overview of potential markets for hydrogen demand distribution in 2050. The prices of hydrogen at customers are willing to buy, assuming the various markets, are retrieved from (Ruth, 2019) and described in the figure below. The assumption is that due to international competition most of these price-levels will also hold on the European market. When possible price data was update by price estimations from Dutch reports. Important to note is that is a positive relation between the price of hydrogen and the quality of hydrogen. The higher the quality of the hydrogen, the higher the price a sector might be willing to pay. The aggregate demand curve represents the total quantity of all goods (and services) demanded by the economy at different price levels. The demand curve is established by combining the expected future demand for hydrogen with the threshold prices from various hydrogen markets.

Sector	Price-estimate (€/kg)	Source
Refining and biofuels	**€2.6**	**(Ruth, 2019, S. 10). Exchange rate or $/€ of 0.88 is applied. Business as usual is used as the threshold price.**
Mobility (LDV, MDV and HDV)	**€4**	**(Gigler, 2018, S. 51)**
Chemicals like Methanol and Ammonia	**€1.8**	**(Ruth, 2019, S. 10). Exchange rate or $/€ of 0.88 is applied. Business as usual is used as the threshold price.**
Metals	**€1.5**	**(Ruth, 2019, S. 10). Exchange rate or $/€ of 0.88 is applied. Business as usual is used as the threshold price.**
Synthetic fuels and other chemicals	**€1.3**	**(Ruth, 2019, S. 10). Exchange rate or $/€ of 0.88 is applied. Business as usual is used as the threshold price.**
Seasonal storage	**€1**	**(Ruth, 2019, S. 10). Exchange rate or $/€ of 0.88 is applied. Business as usual is used as the threshold price.**

Figure 27: Price levels for hydrogen from various sectors based on literature.

	NSE National Management	NSE Regional Management	Hydrogen Roadmap
Electric / seasonal storage	0.1	1.1	1
Mobility (LDV, MDV and HDV)	0.7	0.4	1
Ammonia/Fertilizer	1.2	1.2	4
Industry (heat)	0.6	0.6	1.4
Refinery	0.0	0.0	5.8
Build environment (heat)	1.3	0.0	0.8
Source:	(Afman, 2017); ETM-model National steering[32]	(Afman, 2017) ETM-model Regional steering[33]	(Gigler, 2018, S. 43)

Figure 28: Potential development of Dutch Hydrogen demand in various scenarios

[32] Available at: https://pro.energytransitionmodel.com/scenario/overview/introduction/how-does-the-energy-transition-model-work

[33] Available at: https://pro.energytransitionmodel.com/scenario/overview/introduction/how-does-the-energy-transition-model-work