North Sea Energy
offshore system integration

1.1

North Sea Energy 2020-2022

Energy Hubs & Transport Infrastructure

North Sea Energy 2020-2022

Unlock the low-carbon energy potential North Sea with optimal value for society and nature

The North Sea Energy program and its consortium partners aim to identify and assess opportunities for synergies between energy sectors offshore. The program aims to integrate all dominant low-carbon energy developments at the North Sea, including: offshore wind deployment, offshore hydrogen infrastructure, carbon capture, transport and storage, energy hubs, energy interconnections, energy storage and more.

Strategic sector coupling and integration of these low-carbon energy developments provides options to reduce CO2 emissions, enable & accelerate the energy transition and reduce costs. The consortium is a public private partnership consisting of a large number of (international) partners and offers new perspectives regarding the technical, environmental, ecological, safety, societal, legal, regulatory and economic feasibility for these options.

In this fourth phase of the program a particular focus has been placed on the identification of North Sea Energy Hubs where system integration projects could be materialized and advanced. This includes system integration technologies strategically connecting infrastructures and services of electricity, hydrogen, natural gas and CO2. A fit-for-purpose strategy plan per hub and short-term development plan has been developed to fast-track system integration projects, such as: offshore hydrogen production, platform electrification, CO2 transport and storage and energy storage.

The multi-disciplinary work lines and themes are further geared towards analyses on the barriers and drivers from the perspective of society, regulatory framework, standards, safety, integrity and reliability and ecology & environment. Synergies for the operation and maintenance for offshore assets in wind and oil and gas sector are identified. And a new online Atlas has been released to showcase the spatial challenges and opportunities on the North Sea. Finally, a system perspective is presented with an assessment of energy system and market dynamics of introducing offshore system integration and offshore hubs in the North Sea region. Insights from all work lines have been integrated in a Roadmap and Action Agenda for offshore system integration at the North Sea.

The last two years of research has yielded a series of 12 reports on system integration on the North Sea. These reports give new insights and perspectives from different knowledge disciplines. It highlights the dynamics, opportunities and barriers we are going to face in the future. We aim that these perspectives and insights help the offshore sectors and governments in speeding-up the transition.

We wish to thank the consortium partners, executive partners and the sounding board. Without the active involvement from all partners that provided technical or financial support, knowledge, critical feedback and positive energy this result would not have been possible.

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1 Executive summary

The North Sea has vast potential for European energy supply. North Seas Energy Cooperation (NSEC) countries committed to jointly building 260 GW of offshore wind energy by 2050 in the entire maritime area of the NSEC region (1). This follows on Denmark, Germany, Netherlands and Belgium that announced the aim for 150 GW of offshore wind in the North Sea at the Esbjerg declaration (2). In the Netherlands, this is reflected in the national wind installed capacity target of 21 GW by 2030 with the target growing to up to 40-70 GW by 2050.

This study is the first-ever attempt to design offshore energy system integration hubs in the Dutch part of the North Sea. Energy Hubs are developed as clusters where various functional systems are closely integrated within specific geographical regions. The research consortium developed three energy hubs – namely, Hub West, Hub East and Hub North – and used a multitude of storylines to give insights specifically into the techno-economic aspects, but also involving aspects related to legal, safety, and ecological challenges that are addressed in other NSE 4 work packages. This report aims to present a conceptual vision of the future offshore energy hubs, while rooted as best as possible in state-of-art ambitions pertaining to infrastructure visions.

The energy hubs, as designed in this study, together contribute towards achieving approximately 34 GW Dutch offshore wind installed capacity by 2050. Offshore power to hydrogen platform and islands as the building blocks to scale the installed wind capacity to 70 GW by 2050 are conceptually described. Moreover, the three energy hubs will produce approximately 1.2 Mt/a Hydrogen and 181 TWh/a green electricity. Besides the total volume of hydrogen and green electricity, natural gas production is estimated to be 7.4 bcm/a (equivalent to ~19% of the 2021 Dutch natural gas demand). CO_2 storage is considered in several depleted fields in the North Sea, with the total CO_2 stored amounting to 27 Mt/a.

Energy hubs have the potential to be the connection points linking multiple commodities. The energy hub analysis considered activities like large-scale offshore wind energy, power-to-gas, greenfield development of natural gas, electrification of oil and gas platforms and the subsurface storage of carbon and hydrogen. The demand for new infrastructure was balanced against the co-use and re-use of existing legacy infrastructure. A variety of modes of transport were considered to deliver the electrons and molecules to onshore landing sites. The possibility of international interconnections was also taken into account to facilitate an integrated and international energy transition in the North Sea. A techno-economic model was built and inputs for activities, functions and infrastructure were gathered from a host of grey and scientific literature in consultation with industry and relevant stakeholders. The model was used to analyse the various storylines for each energy hub to evaluate the total Net Present Costs (NPC), including the discounted investment and operational costs for the first investment cycle of the offshore energy hub (2022-2070).

Hub West involved a common implementation of a CCS network through new/existing pipeline networks alongside platform electrification activities for the CO_2 injection platforms in all the hub scenarios. Around 600 Mt of CO2 are considered to be stored between 2025 and 2070 at a total NPC of 460-563 M€. 6.7-8.7 GW of offshore wind capacity is assumed to be installed and 4-5 GW of electrolyser capacity including both storylines with island and/or platform structures. The P2G production and structure costs were slightly higher for platforms (4.93 B€) as compared to islands (4.76 B€). Both re-use of the NGT and a new pipeline have been considered to bring the hydrogen towards shore. If the NGT is not used for any other offshore hubs, both options do not differ significantly in NPC.

The total NPC to develop Hub West individually resulted in 15-22 B€. There is potential for at least electricity, hydrogen and/or CO_2 interconnections between this hub and the UK. If the Draupner-Duinkerke pipeline will be used for either hydrogen or CO_2 in the future, there might be an opportunity to connect to this network as well (France, Belgium and Norway).

Hub East involved a common implementation of greenfield gas extraction, platform electrification, offshore wind production and partial conversion towards renewable hydrogen. 3.4-5.4 GW of offshore wind capacity is assumed to be installed and 4-4.5 GW of electrolyser capacity including both storylines with island and/or platform structures. The hydrogen is foreseen to be landed onshore via the NGT pipeline. The greenfield gas development contains the connection of the N5 platform to the Riffgat windfarm substation and the G17 platform connected to the Gemini wind park and results in a NPC of 814 M€ for production and 47 M€ for platform electrification. The total NPC to develop Hub East individually resulted in 26-33 B€. There is potential for electricity interconnections between this hub and Germany. No existing pipelines are available to provide potential interconnections for hydrogen between this hub and other countries.

Hub North involved a common implementation of greenfield gas extraction, platform electrification, offshore wind production and partial conversion towards renewable hydrogen, and is located the furthest from shore compared to the other hubs. 19.5 GW of offshore wind capacity is assumed to be installed and 8 GW of electrolyser capacity, which is assumed to be located on platforms only because the water depth is too deep for sandy islands. The Hub North storylines were mainly focussed on how to connect this hub to shore by using new and/or existing pipelines, this analysis showed a minimum hydrogen transport NPC of 4.4 B€ (reused NoGaT, 12 GW) and a maximum of 4.8 B€ (reused NoGaT and NGT incl. new section(s), 22 GW). Standalone platform electrification resulted in an NPC of 224 M€. The total NPC to develop Hub North individually resulted in around 34 B€. Due to its central location within the North Sea there is potential with electricity interconnections to all North Sea countries from this hub. Existing pipelines provide opportunities to make interconnections for hydrogen to Norway, Denmark and Germany from this hub. Due to its central location on the North Sea and the circumstance that large volumes of the hydrogen produced – in contradiction to the other two hubs) will not land via the NGT close to the potential onshore hydrogen storage location at Zuidwending, Hub North might be an offshore hub where the option of large-scale offshore hydrogen storage might be explored in the available salt structures or hydrocarbon reservoirs.

Lastly, the value of further **integration of energy hubs** was considered by studying an integrated hubs scenario which shows the interconnections between the three aforementioned offshore energy hubs. As the NGT pipeline is crossing both Hub West and Hub East and is well-located to be connected with a new pipeline to Hub North as well, there exists a realistic chance that the hydrogen flows of the different offshore hubs can be connected. The integrated hubs have a total cost ranging between 62 - 75 B€ with wind farms accounting for 47 - 50% of system costs across all storylines considered.

Table 1.1: Overview of main characteristics of each hub, based on storylines 2(b)

Hub Function	Characteristic	Hub West	Hub East	Hub North	Combined Hubs
Offshore wind	Installed capacity 2050 (GW)	8.7 GW	5.4 GW	19.5 GW	33.6 GW
	Max electricity production volume (TWh/a)	43 TWh/a	39 TWh/a	99 TWh/a	181 TWh/a
	NPC offshore wind (B€)	11 B€	10 B€	16 B€	38 B€
	NPC cables (B€)	1.8 B€	1.2 B€	5.3 B€	8.2 B€
Renewable hydrogen	Installed capacity 2050 (GW)	5 GW	4.5 GW	8 GW	18 GW
	Max hydrogen production volume (Mt/a)	0.48 Mt/a	0.28 Mt/a	0.43 Mt/a	1.2 Mt/a
	NPC hydrogen production (B€)	4.8 B€	6.0 B€	7.1 B€	18 B€
	NPC hydrogen pipelines (B€)	1.6 B€	1.3 B€	4.4 B€	7.3 B€
Natural gas	Max natural gas production (bcm/a)	-	2.0 bcm/a	5.4 bcm/a	7.4 bcm/a
	NPC natural gas production (B€)	-	0.8 B€	0.9 B€	1.7 B€
	NPC platform electrification (M€)	272 M€	47 M€	224 M€	544 M€
CO2 storage	Max CO2 stored (Mt/a)	27 Mt/a	-	-	27 Mt/a
	NPC CO2 storage network (B€)	0.5 B€	-	-	0.5 B€
Total NPC (B€)		**15 - 22 B€**	**13 - 20 B€**	**34 - 35 B€**	**62 - 75 B€**

The study expands on the value of system integration under the NSE program. The defined hubs are suitable locations to develop the initial pilots which are required to move towards the implementation of offshore system integration. The described storylines could be used as a first attempt to develop an integrated vision for the North Sea. Besides, the storylines provide insights into what investments are required to realise infrastructure for offshore energy hubs, involving new designs for offshore P2G platforms and islands. The designs of the hubs should not be considered as the 'single best solution', but as a realistic starting point for further development and realisation of an integrated offshore energy system.

Three key challenges should be addressed when developing offshore energy hubs. The **first** challenge is to address the interdependencies between the involved actors and their functions and facilities which impact the planning and operations of other functions and facilities. A **second** challenge is to align decision-making between the involved actors who are dependent on each other in developing complete the value chains of system integration. Different types of risks were identified which have varying degrees of impact on different stakeholders. For example, opportunities for re-use of natural gas infrastructure for CO_2 or hydrogen depend on the uncertainty of a lifetime expansion for natural gas extraction. Another example is that investments in offshore electrolysis depend on locations of offshore wind parks and decisions onshore end-users will make (e.g. electrification, allowing for natural gas-hydrogen blends etc.). The challenge remains to ensure effective collaboration between stakeholders and to de-risk their investment profiles in order to accelerate the planning and deployment process in the hubs. The **third**, a major challenge is the landfall of immense quantities of electrons and molecules. Consultation with harbours on the Dutch coast concluded that the space required for integrating offshore energy to the mainland is a serious challenge and needs to be a central part of the planning activities for an effective and realistic offshore system integration.

2 Introduction

The North Sea is an energy basin like no other in the world and at the forefront of the energy transition. The massive rollout of offshore wind capacity, combined with emerging technologies like carbon capture and storage and hydrogen production, as well as (declining) activity in gas exploration and production, is needed to fulfil Europe's commitment to the emissions reduction target, recently increased to 55% for 2030. The Netherlands has decided to follow this emission reduction target. Specific to commodities, the EU aims for 300 GW of offshore wind capacity in 2050 and 65 GW of electrolyser capacity in 2030. The Netherlands aims for 38-72 GW of offshore wind capacity and 3-4 GW of electrolyser capacity in 2030. For the other commodities (e.g. natural gas, CO2 storage) no specific targets are set.

In order to meet the above-mentioned targets, North Sea Energy Hubs can be important stepping-stones for large-scale system integration and therefore are one of the central elements in the North Sea Energy project. We define energy hubs as multi-carrier offshore energy systems consisting of production, conversion and/or storage. In this way, energy hubs are search areas for offshore system integration opportunities. The energy hubs are connected to the Dutch shore via (transport) corridors or interconnected internationally.

The main aim of this study is to identify the potential locations for offshore system integration given the existing and planned offshore activities and to perform a first attempt designs of how these Energy Hubs can be developed in the future. Thereby, the following research questions will be answered:

- What are the potential locations for Dutch Offshore Energy Hubs given the existing and planned offshore activities?
- What are relevant building blocks and generic features that can be utilized in every hub to perform system integration?
- How can first attempt designs of the Dutch Offshore Energy Hubs look like, and what investments are required to develop them?
- What are the main interdependencies in the required actions to develop Offshore Energy Hubs?

The North Sea Energy Hubs built further upon the conceptual studies towards offshore electricity grids, offshore energy islands and the individual concepts of system integration, such as offshore P2G and platform electrification. In this report the lessons learned by these conceptual studies will be placed in specific geographical areas including specific timing in order to show how they contribute to the Dutch energy transition. The relation between the designed North Sea Energy Hubs and the remaining NSE 4 program is to support the North Sea Energy Roadmap (WP7) with relevant in-depth scenarios and considerations for techno-economics, ecology and environment, regulations, and safety. In this way, the selection of the energy hubs does not only feed into this study (WP1) but also into the other working lines of the North Sea Energy project. We foresee that these energy hubs will be pivotal areas in the North Sea energy transition, because they can unlock several activities, such as offshore wind production, to be performed further offshore. Therefore these hubs need to be assessed in greater detail to feed the roadmap with relevant knowledge and background.

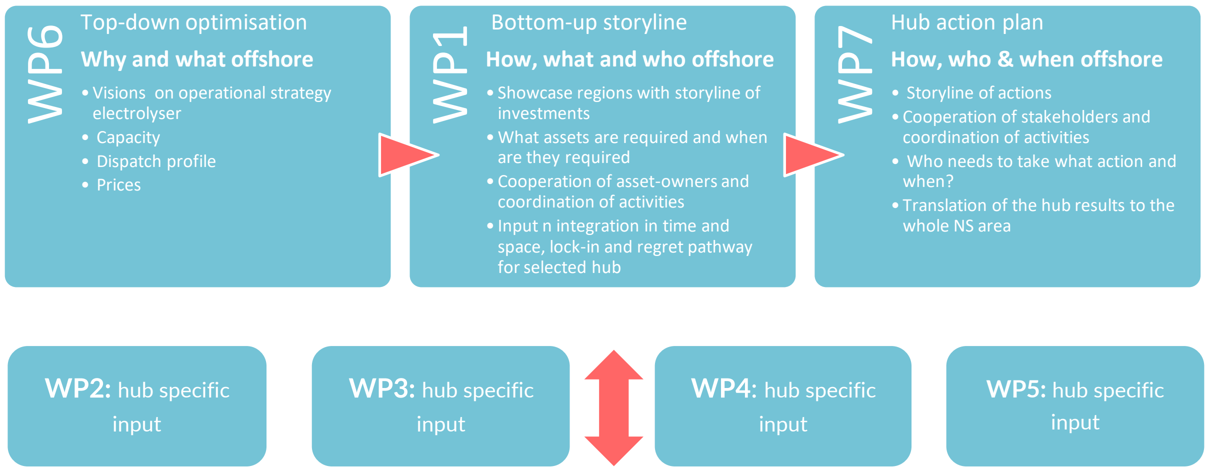

Figure 2.1: Relation between the different activities on techno-economic analysis (WP1), energy system modelling (WP6), roadmap development (WP7) in the North Sea Energy program and with, non-technical 'systems' such as the legal and regulatory frameworks, marine ecosystem, international political agendas and (inter)national governance structures (WP2-5). The current study is limited to WP1.

The work in this specific study has a strong relation with the energy system modelling work (WP6) and hub action plan development (WP7) in the project. Figure 2.1 provides an overview of how these three work packages contribute to the question on how activities offshore can take place. The energy system model yields why and what we can expect to do offshore. This focusses mainly on where dispatch of certain activities, such as hydrogen dispatch can be expected. The techno-economic analysis provides examples of what could be done offshore. We show routes for system integration storylines and the detailed implications of this for techno-economics of the system. The hub action plan finally translates results of both into the how, who & when of activities offshore to pave the way for implementation of various system integration options.

Identifying, understanding, and managing the (inter)dependencies between the large range of activities is not limited to the technology-oriented activities (WP1), as the energy system in the North Sea also comprises of, or has strong relationships with, non-technical 'systems' such as the legal and regulatory frameworks, marine ecosystem, international political agendas and (inter)national governance structures. The relevant information (policy, ecological, spatial, technological, economic, and legal) is gathered through iterative collaboration with WP2-WP4.

The techno-economic analysis will be performed by a sub-working group of the North Sea Energy consortium, consisting of a set of executive (research) as well as in-kind industry partners in the program. TNO and New Energy Coalition coordinate the study. These research partners conduct a large part of the study and are supported by the following industry partners for specific activities: Boskalis, DEME, Bilfinger, HINT, Port of Amsterdam, Port of Den Helder, Port of Rotterdam, Iv-Offshore & Energy, and the Net Zero Technology Center.

This document describes the methodology for this study, as well as a description of the selected energy hubs and corresponding storylines. Chapter 2 describes how we selected the energy hubs and gives a detailed description of the location of the hubs. Thereby, it presents the selected storylines for three selected hubs including system integration elements, strategic infrastructure, and input timelines. Chapter 3 introduces the modelling methodology. We present considerations for the development of the generic techno-economic model and corresponding system boundaries. After that, assumptions and data input for separate functions, facilities and installations that form input to the techno-economic model are presented. Chapter 4 summarizes the modelling outcomes for system integration elements and the storylines as presented in Chapter 2. Chapter 5 provides recommendations to realise offshore energy hubs, based on the dependency structure matrix analysis. Chapter 6 reflects and concludes the report to put the main findings and challenges of the report in perspective.

3 North Sea Energy Hubs

3.1 Description of North Sea Energy hubs

We define energy hubs as multi-carrier offshore energy systems consisting of production, conversion and/or storage. In this way, energy hubs are search areas for offshore system integration opportunities. The energy hubs are connected to the shore via national (transport) corridors or interconnected internationally. Offshore system integration is defined as a set of sector coupling activities including: (platform) electrification, CO_2 storage, Power2Gas (P2G); and green field natural gas production. Energy hub storylines are specific scenarios of these system integration elements that relate to each other. A storyline contains specific choices to include or exclude a certain activity but can leave approaches open for other choices.

Storylines for the specific energy hubs are determined based on three steps:

- Knowledge and insights from other relevant studies, including previous phases of the North Sea Energy program.
- Input from the North Sea Energy program during the Scoping Workshop
- Validation by the relevant asset owners in the specific energy hubs

This input was combined to a workable set of storylines for the hub regions. Each storyline was built up from the building blocks for offshore system integration. Figure 3.1 shows these building blocks. The building blocks can be divided in four elements on which you can choose the set-up of a storyline.

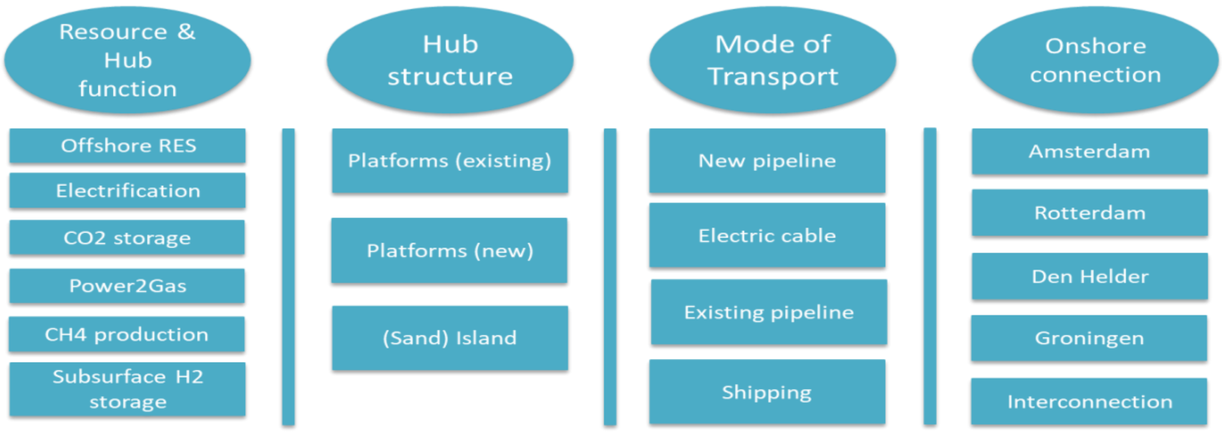

Figure 3.1: Building blocks for offshore system integration.

The first element comprises of what functions an energy hub can serve in the system. These hub functions are a result of activities in scope from earlier phases of the North Sea Energy project as well. The second element is the hub structure. This describes the type of structure that houses the different hub functions. In this project, we make use of either platform or sandy island structures as a base for the activities. The third element is the mode of energy transport that will be considered. This includes either transport through electricity cable (electricity) or pipelines (natural gas, hydrogen, CO_2). For CO_2 specifically, shipping can also be considered. The last element is the onshore connection. Transport of energy carriers can connect to the onshore system through different routes. We make use of the typical landing points for energy that are known in the Netherlands, as well as the option to make interconnection to other (North Sea) countries. Depending on the hub specifics, a selection of building blocks will apply and shape the storylines for the energy hubs.

The North Sea Energy Hubs are chosen based on several assessment criteria combined with expert-knowledge within the project consortium. The assessment criteria were:

- Expected future offshore wind developments, mainly the outlook 2030-2040.
- Availability of existing infrastructure.
- Expected activities in the field of gas, electricity, hydrogen, and CO2.
- Data availability.
- Potential for international interconnection.
- Ecological circumstances.
- Landing and market opportunities.

The combination of these assessment criteria above yielded the selection of three energy hubs in the Dutch part of the North Sea. Figure 3.2 shows the location of the three energy hubs - Hub West, Hub East and Hub North respectively. The next section will provide in-depth descriptions of the different hub regions as well as the specific storylines for these hub regions.

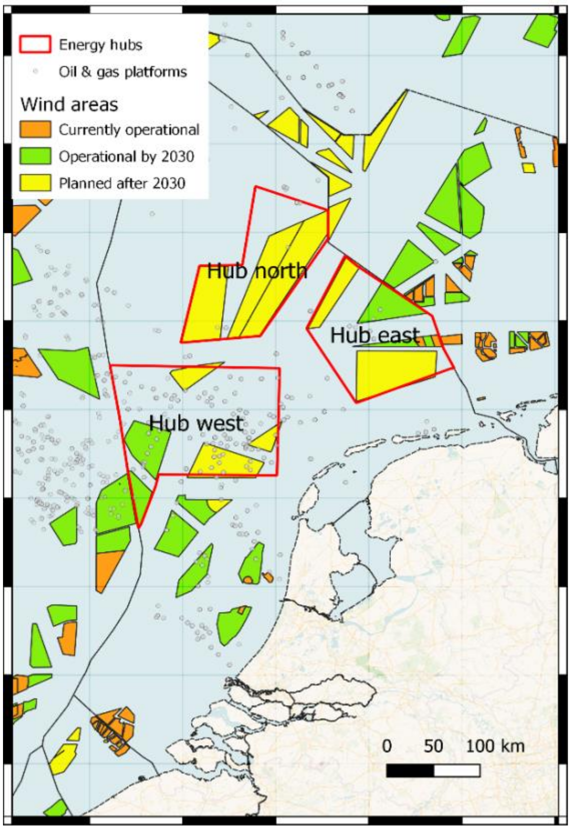

Figure 3.2: Selected energy hubs and planned and existing offshore infrastructure up to 2040s

3.2 Hub West

Hub West covers a major part of the western part of the Dutch continental shelf. This area covers e.g., activities within the K/L blocks for oil & gas E&P licenses, wind developments around and on top of IJmuiden Ver and other potentially planned tendering areas south of the Cleaver Bank. Since this area is located close to the border with the UK Continental Shelf, potential international interconnections could be foreseen.

Existing gas infrastructure

Hub West holds a strong set of activities in the field of gas production from the K-L blocks. We selected five key platforms that we expect to have an important role in Hub West. The selection was based on a combination of production potential, CO_2 storage potential [1], known initiatives and studies for these assets in system integration and input of the asset owners. The key platforms – highlighted in Figure 3.3 - are: K5 (Operator: Total E&P), K8 (Operator: NAM), K14 (Operator: NAM), K15 (Operator: NAM), and L10 (Operator: Neptune Energy).

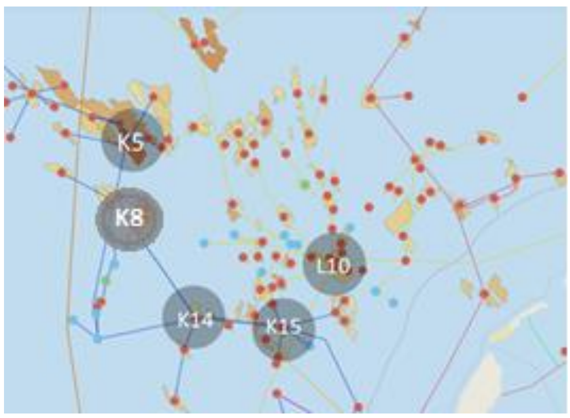

Figure 3.3: Overview of key infrastructure assets selected for hub West

[1] In section 3.2.3 more information on the CO2 storage potential is given

The area is very well connected to the shore via several major pipelines such as WGT (36") to Den Helder, LOCAL (24") to Den Helder and NGT (36") to Groningen. The expected end of life for most assets in Hub West is expected to be after 2027 (7). Because of the large availability of gas-producing reservoirs, the expected storage potential for CO_2 in the area is extensive as well. For some of the major platforms in the area, CCS feasibility studies are already announced (e.g., L10) (7).

Future wind developments

Hub West is located closely to the tender area of IJmuiden Ver including its potential new tendering area extending to the north. Ijmuiden Ver is expected to cover 4 GW of wind energy coming online in 2027/2029 (8). In the current plans, IJmuiden Ver will be fully connected to shore via electricity cables landing at Maasvlakte/Simonshaven (IJmuiden Ver Beta 2 GW) and Borssele/Geertruidenberg (IJmuiden Ver Alfa 2 GW).

Areas for wind tendering for the period 2030-2040 were released in 2021 by the Dutch government. These areas could play an important role for activities in Hub West since they may become available for other ways of connection to shore than electric transport. Specific areas of importance are:

- Area 1: South-east of Hub West (0 GW - 6 GW)
- Area 2: Potential extension of the IJmuiden Ver area in the North (2 GW - 5 GW)
- Area 3: South-east of the Cleaver Bank region (0 GW – 2 GW)
- Area 8: L10-area (2 GW)

Areas 1, 2, and 8 have been considered (partly) for system integration developments in Hub West.

Onshore connection & regional market

Transport of energy carriers to and from Hub West is important to ensure successful activities in the area. For pipeline transport, it was already mentioned that Hub West is well connected to Den Helder and Groningen via three major pipelines. Den Helder in that way provides good pipeline connection to Hub West. The capacity of the electricity grid in this area is limited for large-scale influx of electricity. Thereby, onshore electrical capacity in Noord-Holland is limited as well. Potential increase in electricity demand may be expected from the development of data centres in the area. Currently there are no local CO_2 sources available, though regional production of blue hydrogen (with corresponding CO_2 source) is currently under study.

Connection to the Amsterdam-IJmuiden Offshore Port region and the Rotterdam area can be considered as another route. Large-scale wind capacity from IJmuiden Ver will already be connected to the Rotterdam area. In addition, the Amsterdam-IJmuiden region will be used for offshore wind connection (e.g., Hollandse Kust Noord and Hollandse Kust West-Alpha) (5). Thereby, both the Rotterdam and Amsterdam-IJmuiden region can be expected to be growth areas for regional energy demand (both electricity and molecules).

Interconnection

Since Hub West is located close to the border with the United Kingdom continental shelf, potential for interconnection of electricity, hydrogen and CO_2 should not be excluded. Interconnection of electricity is already under study by TenneT and National Grid to develop a multi-purpose interconnector of 2 GW between IJmuiden Ver and an UK wind farm.

3.2.1 Building blocks for system integration

Figure 3.4 shows the selected building blocks for Hub West. These building blocks are the base for the storylines for this area and the establishment of three main hub offshore system integration activities: Electric System Integration, CO_2 storage network and P2G network.

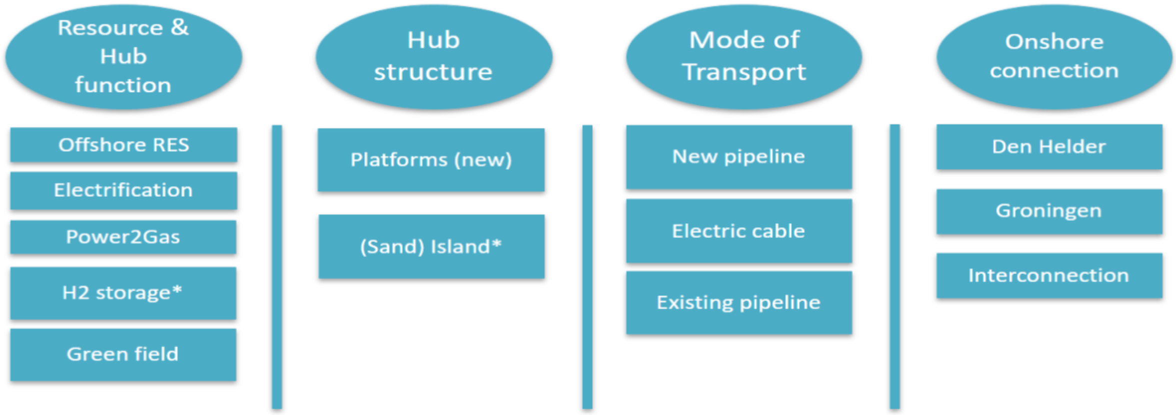

Figure 3.4: Building blocks for system integration in Hub West.

3.2.2 Storylines

Based on the building blocks and the input we collected for relevant activities in the area, we set up three storylines for hub West based on the role and form of P2G in the hub. Based on the storylines (discussed hereafter), we set up an input timeline for all activities. Input for this was based on existing plans for future wind, gas production and CCS and was validated with the relevant asset owners. Please note that timelines will also strongly depend on the interdependencies of the different activities. For that reason, several choices under study will have an influence on the selected timeline. A summary comprising of investment dates, horizons and capacity of all system integration activities is provided in Appendix A.

3.2.2.1 Key generic features

All storylines contain a set of common activities and characteristics:

- Storage capacity is available in a multitude of offshore gas fields, most of which are expected to become depleted in the coming decade. Both the national target and the objective of the various harbours for the development of CCS requires a fast and efficient build-up of CO2 transport and storage infrastructure that connects the main industrial regions in the Netherlands with offshore storage capacity (10). Most of this storage capacity is located in Hub West and hence CCS takes place at all key platforms in each storyline by re-using the existing gas production platform for injection.
- Where possible, inter-field pipelines in Hub West are re-used for CO2 transport. CO2 transport from the connecting areas onshore to Hub West is expected to take place through existing and/or new pipelines (discussed in detail later on). CO2 transport by means of shipping will also be studied as an alternative.
- Generating about 15% of the total national greenhouse gas emissions, the industrial cluster in the Port of Rotterdam aims to capture and store up to 5 Mtpa by the mid 2020's to realize part of the governments objectives (10). Large sources of CO2 are also in the industrial region near Amsterdam (IJmond), with Tata steel emitting about 6 Mtpa, was initially part of the analysis. Though, the abandonment of the Athos project makes the development of a CO_2 pipeline network starting in IJmuiden less likely. The H2Gateway facility, which might be established in Den Helder by 2028, is expected to deliver volumes up to 2 to 4Mton per annum. The Netherlands government has a stated objective to develop CCS for industrial sources and waste incineration on a large scale, aiming to achieve a capture and storage rate of 7 Mtpa by 2030.
- Platform electrification through offshore wind electricity for gas production and CCS only is not considered. If P2G is planned at a later stage in the storyline, electrification of these processes is considered. When no P2G is planned around a platform location, electricity demand for CCS will be

produced decentralized at the platform location. The electricity is expected to be provided with diesel generators, but further analysis will be performed to indicate decarbonisation strategies for the CCS injection process.

- If platform electrification is considered, it will take place via connection with wind parks located in "Hollandse Kust West Area" or via new search areas for wind energy north of Hub West.
- The required electrical equipment for electrification is expected to be placed on a separate, new platform.
- P2G on platforms will only be considered at new platforms that will be placed around the existing platform. The landfall of electricity, in connection with the potential massive increase of wind development in the Hub West region, would be interesting to explore since TenneT is working ~~hard~~ to strengthen the electricity system.
- Since interconnection of various energy streams is an important feature, we will also discuss various interconnection options through the various storylines. For CCS, we will explore options for delivery of CO2 from the United Kingdom (Bacton/Teeside) to store in Hub West. Thereby, we will also discuss the option to provide electrical interconnection with the United Kingdom.

3.2.2.2 Storyline 1: P2G on a sandy island[2]

In this storyline, a dedicated P2G infrastructure in Hub West will be located on an artificial island, instead of using platforms, in the proximity of the K8 area (wind area 1). In this storyline, the produced hydrogen will be transported to shore by a new, dedicated hydrogen pipeline in the same corridor as the electrical transmission system. As sub scenarios co-use and re-use of the NGT and or WGT network is considered. Potential routing decisions are discussed in further detail later on. The expected P2G capacity, via direct coupling with the offshore wind park 'area 1', will be about 4 GW.

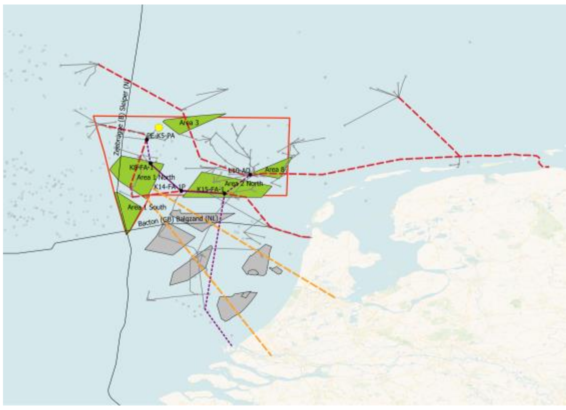

Figure 3.5: Hub West Storyline 1

3.2.2.3 Storyline 2: Dedicated P2G on multiple platforms

In this storyline, dedicated P2G in Hub West will be clustered around platform K8 on a set of multiple new platforms. The total expected P2G capacity will be about 4 GW. For P2G sizing on a single platform, we assume a hydrogen production platform of 500 MW. This means that depending on final sizing some 6-8 new platforms will be placed around K8 for dedicated P2G production with electricity from offshore wind park 'area 1'. Electrification of K5 will take place through K14 from Hollandse Kust West, which, once a short connection to K8 is realised, will also ensure a small baseload grid connection of the P2G installations. This electrification can also be

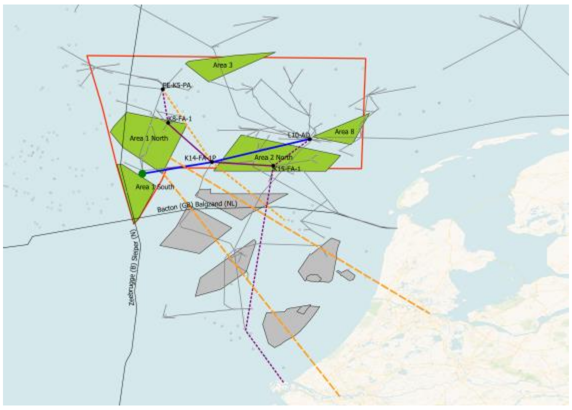

Figure 3.6: Hub West Storyline 2

[2] In addition, Power2X may be considered. A prime example is to use locally produces Hydrogen for Methanol synthesis, using CO2 from the mainland on the island. This option is not ignored, though, would not be considered in the detailed plot designs of the Island. NSE 3 provides already a first indication on the potential of offshore Power2Methanol.

used for CCS at K14 and K5. Large-scale electrification for P2G will then be established through to be planned wind areas north of Hub West. Optimal ways of transport of hydrogen from K8 to shore will be studied. This could be either through re-use of inter-field pipelines or new, dedicated hydrogen pipelines.

3.2.2.4 Storyline 3: Dedicated P2G on multiple platforms & flexible P2G at single platforms

In this storyline, dedicated P2G at K8 will take place in a similar manner as for storyline 2. Additional, flexible P2G at L10, K14 and K15 with electricity from IJmuiden Ver is considered as well and it does include electrification of these platforms through Hollandse Kust West and/or via indicated wind areas 2 and 8. In this storyline, L10 will serve as a collection hub for hydrogen produced at the other key platforms.

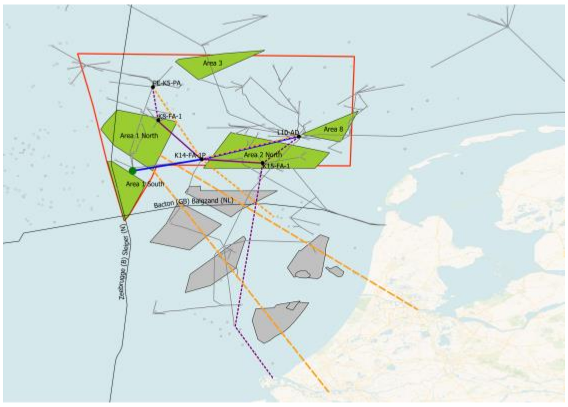

Figure 3.7: Hub West Storyline 3

3.3 Hub East

Future wind developments

The only operating wind park located in Hub East is the Gemini wind park, currently at 600 MW capacity (7). In the same area, 700 MW additional capacity is planned at the wind park Ten Noorden van de Wadden (TNVDW) which should be operational by mid to end 2020's. This is expected to be connected by 220 kV HVAC connection to the shore. In addition, specific areas of importance in the new tendering areas are Area 4 (build out capacity further TNVDW – below Gemini (5 to 10 GW)) and Area 5 (to the north of the G-block area (4 to 6 GW)). These wind areas are currently also under consideration for dedicated onshore hydrogen production such as in the NortH2 project (11) Considering its proximity to the German border, interconnection with existing and planned German wind farms may be of interest as well. For example, ONE-Dyas is exploring opportunities to electrify their green field development at N5 via the German wind park Borkum-Riffgat (113 MW in operation since 2014) (12). Similarly, the BorWin area on the north side of Hub East (2.1 GW in operation, 1.8 GW planned by 2025-2027) may offer opportunities for cross-border interconnection. Figure 3.8 gives an overview of operational and planned wind farms on the German continental shelf and their relative location to the Dutch wind park Gemini.

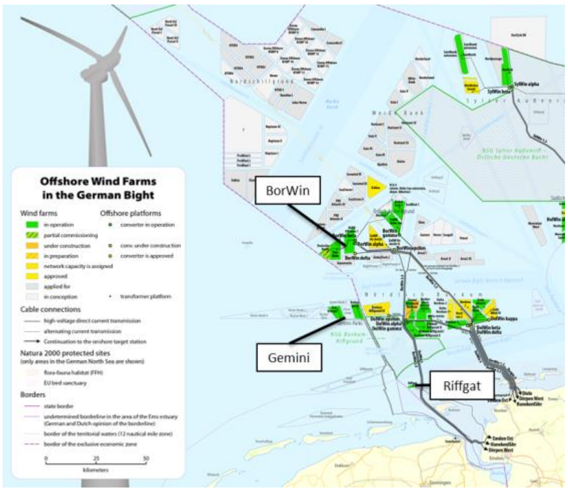

Figure 3.8: Offshore Wind farms on the German Continental Shelf (61)

Existing and new gas infrastructure

Natural gas plays an important role in the transition to a fully sustainable energy supply in 2050. Dutch gas is preferable to importing foreign gas. Because Dutch natural gas is cleaner, cheaper, it makes our energy supply more independent from abroad (13). While we are accelerating the phase out of natural gas extraction in the Groningen field, gas extraction from small fields might be stimulated as this has less impact on the climate than imported gas. Hub East currently holds a set of gas production activities in the G-block with G17 as the major gas-producing platform. Expected end of life gas production in the region is 2036 (14), though scenarios vary significantly (7).

Greenfield natural gas development is at the base of the Hub East storylines. A consortium led by One-Dyas has initiated gas production process from the N05-A gas field and it is very likely that other small fields can be developed in the vicinity of this field as well (see Figure 3.9). Water depths are about 25 m and the gas itself around 4km deep in the surface (15). The realisation phase in the GEMS project is expected to start in 2022, whereas exploration activities are expected to begin in 2024. This phase takes on average 10 to 25 years (16).

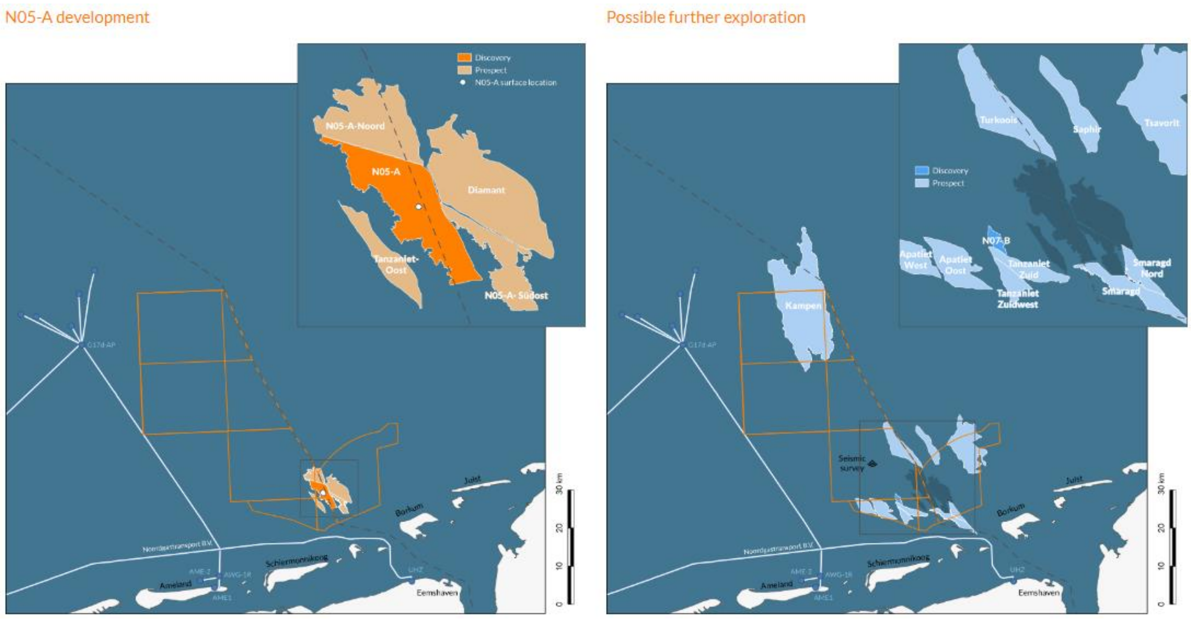

Figure 3.9: N05-A surface location and prospects in N-block (12)

The baseline extraction profile for the N05 field and combined with the prospects (N05-A-Noord, Tanzaniet-Oost, Diamant, and N05-A-Südost). Other discoveries can be extracted via a separate satellite platform located at some 10km from the main production platform. The potential of these reservoirs is still unknown, though, the public extraction profile can be taken from the exploration plan (17)

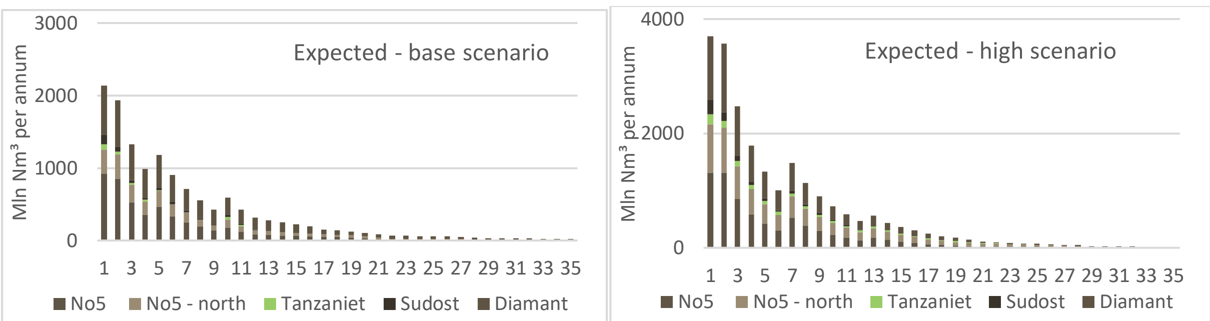

Figure 3.10: extraction profile (base-case) for N5. Taken and translated from the exploration plan (13)

Onshore connection & regional market

The NGT-pipeline is an existing main transmission pipeline to transport gas from various offshore gas production platforms to the mainland. Hub East currently holds a set of gas production activities in the G-block with G17 as the major gas-producing platform. Expected end of life for the platforms in the

region is a bit earlier than for Hub West. Scenarios vary from 2023-2027 towards 2036 for the bigger platforms (7), (14). However, the area is also under quite a bit of exploration for new gas fields.
Green field gas supplied to this line must meet certain specifications. Pre-treatment of the gas is therefore a requirement. The N05-A platform will be designed as a gas treatment platform, which will then be connected to the NGT pipeline with a newly constructed pipeline. The new, 20-inch, pipeline will have a length of approximately 13 kilometres. Since there are many stones in that area, lowering the pipeline into the ground by its own weight can be a problem due to the stony surface. In addition, the gas supplied must meet the pressure requirements set by NGT. There are some considerations by NGT to reduce the operational pressure, however, for this analysis the pressure is set between 85 and 90 bar (13).

Because of its proximity to the Eemshaven, it is a logical routing to land various energy carriers from Hub East in this area, either via cable or pipeline. Several large cable and pipeline initiatives already land in the Eemshaven such as the COBRA cable of 700 MW to Denmark, the NorNed cable of 700 MW to Norway and the NGT pipeline. A challenge for onshore connection is the fact that all transport connections have to cross the Waddenzee area, which is a well-protected nature area. The regional market in the Eemshaven and Delfzijl can be seen as well developed, since it is an energy intensive region. The Eemshaven region has a high potential for decarbonisation in the existing industrial sector and may therefore be a regional user for electricity as well as hydrogen from Hub East. Given the proximity to the German Continental Shelf as well as the availability of operational wind parks close to the Dutch border, an interconnection with Germany is likely.

3.3.1 Building blocks for system integration

Figure 3.11 shows the selected building blocks for Hub East. These building blocks are the basis for the storylines for this area and the establishment of three main hub offshore system integration activities: electric system integration, integrated green field natural gas production and, a P2G network.

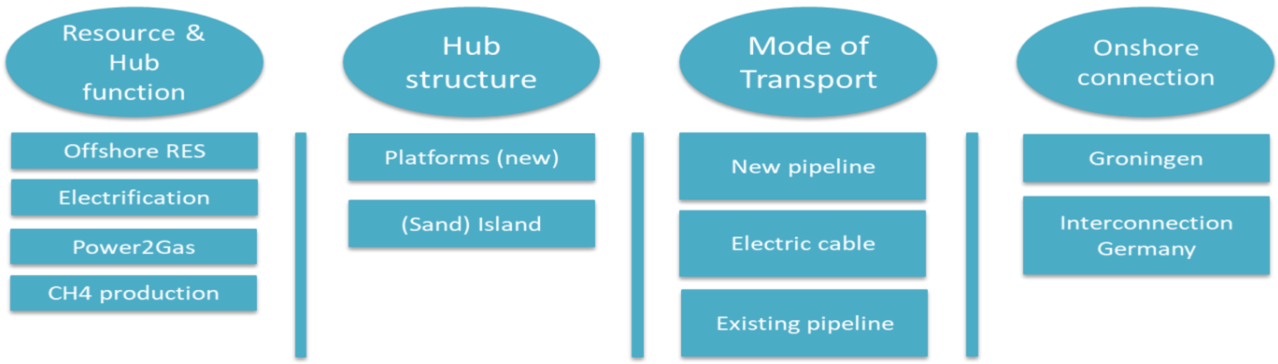

Figure 3.11: Building blocks for system integration for Hub East.

3.3.2 Storylines

Based on the building blocks and the input we collected for relevant activities in the area, we set up three storylines for Hub East based on the role and form of P2G in the hub. Thereafter, we set up an input timeline for all activities. Input for this was based on existing plans for future wind and gas production and was validated with the relevant asset owners. Please note that timelines will also strongly depend on interdependencies of the different activities. For that reason, several choices under study will have an influence on the selected timelines. A summary comprising of investment dates, horizons and capacity of all system integration activities is provided in Appendix A.2.

3.3.2.1 Key generic features

All storylines contain a set of generic activities and characteristics:

- Because it is a green field development, N5 will be electrified in each storyline. Electrification will take place from the German wind park Riffgat with a connection to the German grid. Electrical equipment will be hosted on the main platform.
- G17 will only be electrified if it will host P2G activities on the long term. Electrical equipment for electrification will in that case be hosted on a new platform. Electrification of G17 will go through at least TNVDW. Additional energy for electrification may come from German wind parks or to be announced tendering areas for the period 2030-2040.
- Both N5 and G17 will host small-scale P2G production at some point in the storyline. This produced hydrogen will be admixed into the NGT pipeline for transport to shore.
- P2G on platforms will only be considered at new platforms that will be placed around the existing platform.
- Since interconnection of various energy streams is an important feature, we will also address various interconnection options for the various storylines. For Hub East, we will discuss the possibilities of providing electrical interconnection with Germany via the energy islands in Storyline 1 and 2. This will focus on the BorWin wind areas as well as Riffgat wind park.
- CCS is not part of Hub East storylines. The Dutch Continental Shelf is expected to have a storage capacity of about 1685 Mt, of which most (some 675 Mton) is located in Hub West (10) (18). The developed roll-out scenario in NSE 3 (19), which includes the fields that are currently included in Hub West, shows that CCS rates can only be supported until 2045. Post-2045, sufficient additional capacity can potentially be developed though in other fields offshore, in particular in the E, G, J, K, and L blocks. The G14-platform – located in Hub East – can store about 30Mton of CO2, though, the lack of other nearby storage sites would bring UTC for CO2 storage to relatively high levels.

3.3.2.2 Storyline 1: Dedicated P2G on a sandy island

In this storyline, dedicated P2G with electricity from offshore wind farm 'area 5' in Hub East will be located on an artificial island structure next to this wind park. The produced hydrogen will be transported to shore by a new, dedicated hydrogen pipeline, potentially combined with the electric corridor. As sub scenarios concerning co-use and re-use of the NGT is considered as well. Potential routing decision are discussed in further detail later on. The expected P2G capacity will be about 4 GW.

3.3.2.3 Storyline 2: Flexible P2G on a sandy island

In this storyline, the function of the artificial island changes compared to storyline 1. For this storyline, the island provides electricity and hydrogen transmission in a fixed ratio (50:50) to provide a more flexible P2G set-up. Expected capacity will be similar to storyline 1, though, the dispatch profile for the electrolyser will follow market conditions, meaning that power will be taken from onshore to produce offshore P2G when prices of electricity are below the benchmark price of electricity for producing hydrogen.

3.3.2.4 Storyline 3: P2G on multiple platforms

In this storyline, dedicated P2G in Hub East will be clustered around G17 on a set of multiple new platforms. The total expected P2G capacity will be about 4 GW. For P2G sizing on a single platform, we assume a hydrogen production platform of 500 MW. This means that depending on final sizing, 6-8 new platforms will be placed around G17 for P2G production. Optimal ways of transport of hydrogen from G17 to shore will be studied. This could go through a blending scenario for NGT transitioning from a gas pipeline either to a hydrogen pipeline or to the development of a dedicated hydrogen pipeline.

3.4 Hub North

Hub North is located in the central area of the Dutch Continental shelf. The area is associated with significant wind developments in the long term (expected post-2030) and provides serious opportunities for offshore hydrogen production, although its relatively large distance to shore. Since this hub is quite centrally located in the North Sea, international interconnection of electricity and hydrogen with other North Sea countries such as the United Kingdom, Germany, Denmark, and Norway is foreseen. The development of platform structures is envisioned for this hub, as water depths are relatively high.

Future wind developments

Specific wind areas of importance for Hub North are area 6 and 7 which have a combined potential of 18 GW. These areas are also under consideration for the second phase of NorthH2 and by the NSWPH initiative (11). Due to its proximity to various other North Sea countries, interconnection with existing and planned wind farms may be of interest as well.

Existing and new gas infrastructure

Hub North has a set of activities in the field of oil & gas production from the F-blocks. We selected a number of key platforms that may have an important role in Hub North. The selection was based on a combination of production potential, known initiatives and studies for these assets in system integration and input of the asset owners. The key platforms are: F3-B (Operator: GDF Suez), L2 (Operator: GDF Suez), and F15-FA (Operator: Total). On the short-term prospective shallow-gas and -oil developments can be expected at F-05A & B and F-06 IJsel respectively. In the longer term, possible oil developments around F17 can be established. A hub will arise which could make nearby (oil) prospectively around L2 commercially more attractive (14). Figure 3.12 shows the location of these key platforms in Hub North.

The area is very well connected to the shore via the NoGaT pipeline (36") to Den Helder. The expected end of life for most assets in Hub North is expected to be after 2027 (7).

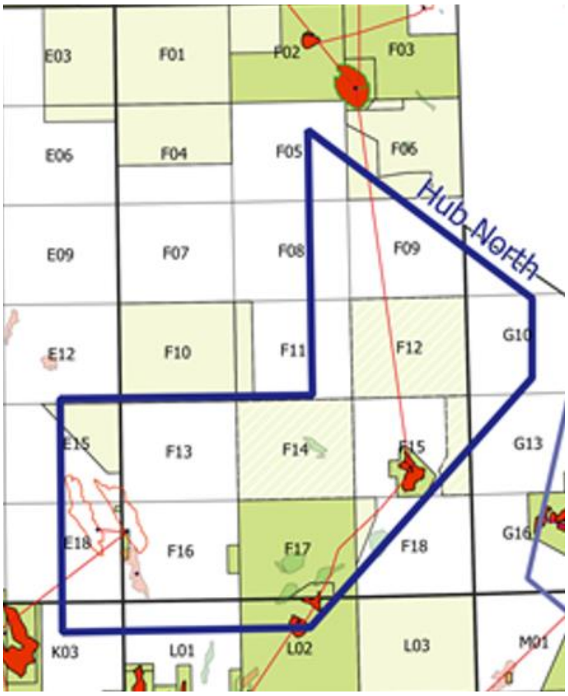

Figure 3.12: Overview of key infrastructure assets selected for hub North (14)

Onshore connection & regional market

Transport of energy carriers to and from Hub North is important to ensure successful activities in the area. Hub North is well positioned – partly due to the foreseen capacities of offshore wind – to become an offshore international connection point. Due to the international interconnections of electricity with various regions, offshore P2G facilities can, apart from being connected to RES production facilities, also act upon variations in markets prices between the various NSE markets. Especially connections to Norwegian and Danish electricity market seem promising due to the volatility in these markets towards lower price levels. Apart from electricity, there is the potential for developing an interconnection for CO2 transport and storage with Norway which is planning large-scale CCS projects (like Northern Lights and Smeaheia) in the Norwegian Continental Shelf.

The 36-inch NoGaT can bring gasses (CH4, blended gas streams and potentially pure hydrogen) to the landfall point in Den Helder. The existing pipeline network is crossing the German Continental Shelf and connected – if streams can be reversed – that a pipeline connection, connecting the Netherlands to Denmark is already present.
The 10 GW long term ambition of the Norwegian clean hydrogen for Europe initiative considers new and existing transport options (e.g. Zeepipe IIB and Europipe). Further discussions are needed to see how these developments could interact with developments of Hub North and the NoGaT pipeline specifically.

3.4.1 Building blocks for system integration

Figure 3.13 shows the selected building blocks for Hub North, these building blocks are the base for the storylines for this area and the establishment of three main offshore system integration activities: electric system integration, integrated green field natural gas production and, a P2G network.

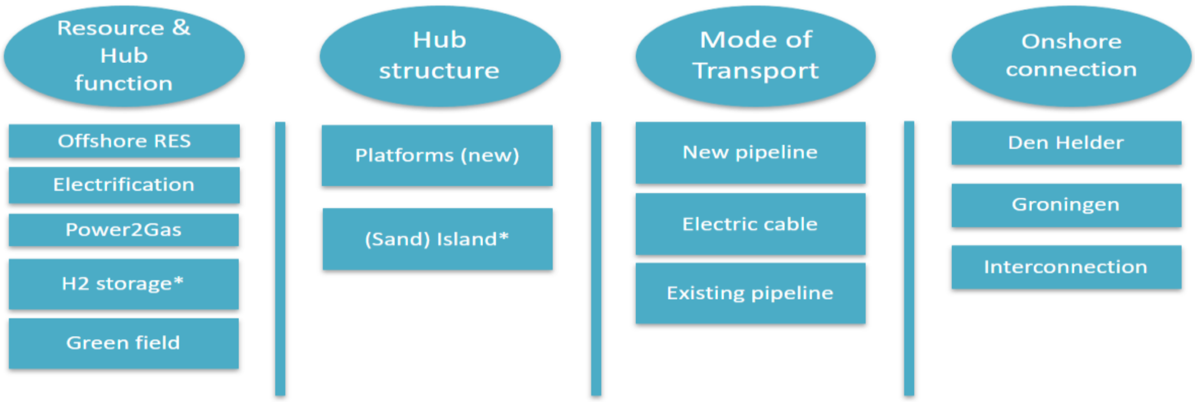

Figure 3.13: Building blocks for system integration in Hub North. The island inclusion is subject to technical feasibility in deeper water depths. Sandy island structures are not expected to be feasible. H_2 storage function will be limited to estimation of storage capacity needed, and will not include detailed sub-surface, geological, and well compatibility.

3.4.2 Storylines

Based on the building blocks and the input we collected for relevant activities in the area, we set up three likely storylines for Hub North based on the role and form of transport in the hub. Thereafter, we set up an input timeline for all activities. Input for this was based on existing plans for future wind and gas production and was validated with the relevant asset owners. Please note that timelines will also strongly depend on interdependencies of the different activities. For that reason, several choices under study will have an influence on the selected timelines. A summary comprising of investment dates and horizons of all system integration activities is provided in Appendix A.2.

3.4.2.1 Key generic features

All storylines contain a set of common activities and characteristics:

- Potential prospective fields are developed via sustainable - future hydrogen ready - infrastructure. This includes electrification of the CH4 extraction process as well as potential re-use of platform structures for hydrogen production. Green field developments are expected to become operational by 2024/2025.
- Existing production platform F3/F15 will be electrified at an early stage.
- An additional exploration on standalone platform electrification will be performed for this hub, because of the long distances towards shore.
- From 2028, small scale hydrogen production around F3 will take place. H2 produced will be admixed in the NoGaT pipeline. The H2Gateway facility, which might be established in Den Helder by 2028,

is expected to accept the admixed gas stream. Additionally, H2Gateway can handle varying volumes (both short term-hourly as well as longer term - over the years) of blended streams of hydrogen and CH4.

- By 2030, offshore wind installation in the region is assumed to increase annually by 2 GW . Hydrogen production capacity will increase by 1 to 1.5 GW per annum (assumed). Large scale hydrogen will be produced on multiple platforms. Sandy island structures will be unlikely given the depth levels (above 40m) in this region. The constellations of these hydrogen facilities will sum up to some multiples of 4 GW (assumed). The feasibility of other island structures, like caissons of floating structures, has to be analysed in further detail in future research.
- By 2040, around 10 GW of transmission connections will be realised, with an electric connection to all of the North Sea countries. This enables the region to make use of price variation between the regions. WP6 specifically highlights the increased need for interconnection capacity between the Netherlands and the UK (sevenfold), and Netherlands and Germany.

3.4.2.2 Storyline 1: Focus on re-use of the existing infrastructure (see Figure 3.14)

The annual increase in P2G activity from area 6 and 7 will increase the yearly volume of hydrogen admixed in the gas stream flowing through NoGaT. The availability of NoGaT reduced procurement need for new infrastructure for hydrogen production infrastructure projects. The blended gas stream is transported to the H2-Gateway project, which would first separate the green hydrogen molecules and thereafter reform the CH4 into blue hydrogen and CO_2. Hence, there will be an interaction with the CO_2-storage network considered in Hub West and the (green field) CH4 production activities in Hub North. To verify technical feasibility, hourly and annual gas flow rate and hydrogen concentration will be shared with the H2 Gateway project for validation. Temporary storage of blended streams can take place at the L9/F3 location when less variability in flow rates is requested. Further research on this is needed.

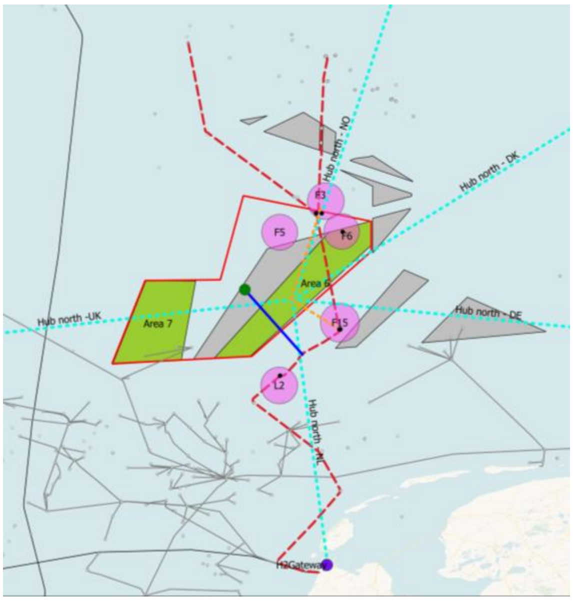

Figure 3.14: Overview of storyline 1

The NoGaT production profile will also provide insights in the need for additional compression capacity, which will be required to ensure hydrogen injection into the NoGaT gas mixture. The upstream pressure at F3 is about 120 bar, so offshore hydrogen compression up to 120 bar is foreseen. This may be lower if different criteria are set at the landfall location in Den Helder. International hydrogen connection capacity might be limited since most of the NoGaT capacity is required to support offshore hydrogen production on the Dutch continental shelf.

3.4.2.3 Storyline 2a: Focus on making a network of existing infrastructure (see Figure 3.15)

By the early 2030´s combined offshore wind and hydrogen developments will take off in area 7. The area – good for an indicative 8 GW of offshore wind – will at least host 4 GW of hydrogen production which will be connected via a new to be build side-tap to the NGT network. This new pipeline – and the NGT - will transport pure hydrogen, and it is assumed that N5 has had its major years of production by then. Compression of hydrogen can potentially take place at the L10 central area (which will also support small scale hydrogen in the Hub West Storyline 3). and pure H2 storage will take place in HyStock salt structures in the Netherlands (onshore). An interconnection from the NGT with the UK wind/hydrogen production areas could be realised as well. This be part of the discussion of the results. Due to the availability of two exporting trunklines from Hub North, additional capacity will be available for international hydrogen transmission. By 2040, large extent of the NOGAT pipeline will be filled with hydrogen coming partly from cross-border regions, like Norway, UK & Denmark.

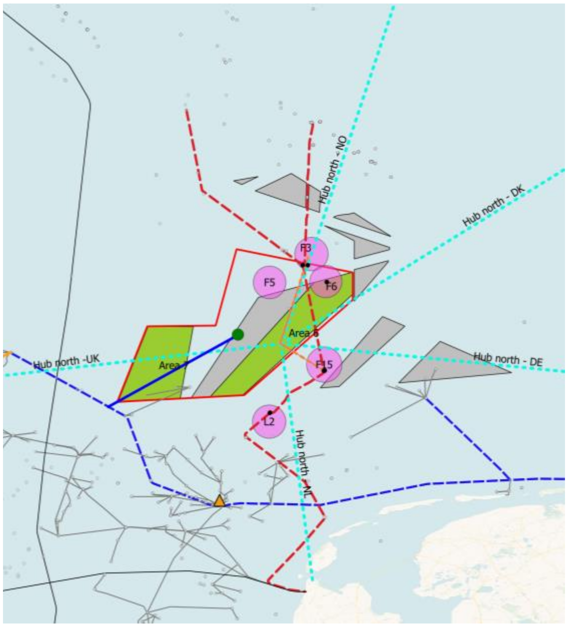

Figure 3.15: Overview of storyline 2a

3.4.2.4 Storyline 2b: Focus on making a network of existing infrastructure (see Figure 3.16)

By 2034/2035 a side connection with the NGT will be made via area 6&7 to the G17 platform. This implies that Hub North activities will be interacting with the P2G activities in Hub East. This new pipeline – and the NGT - will transport pure hydrogen, and it is assumed that N5 has had its major years of production by then. Compression of hydrogen will take place at the G17 central area and pure H2 storage will take place in HyStock salt structures in the Netherlands (onshore).

An interconnection from the NGT with German wind/hydrogen production areas could be realised as well. This should be analysed in further detail. Due to the availability of two exporting trunklines from Hub North, additional capacity will be available for international hydrogen transmission. By 2040, large extent of the NOGAT pipeline will be filled with hydrogen coming partly from cross-border regions, like Norway, UK & Denmark.

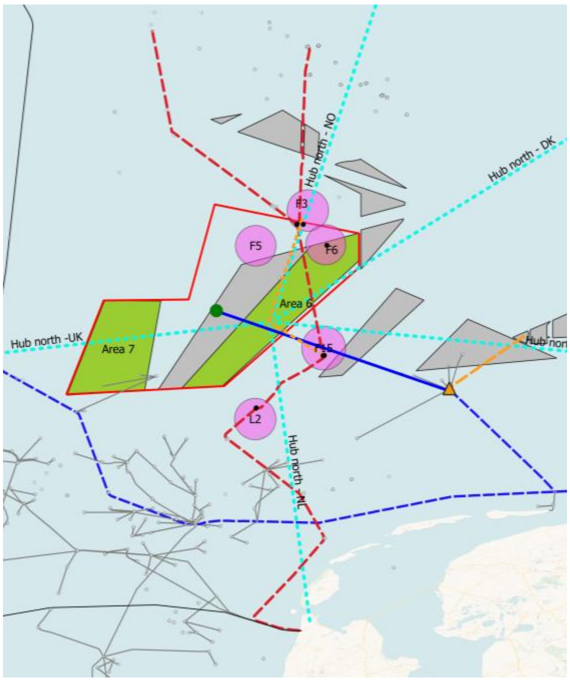

Figure 3.16: Overview of storyline 2b

3.4.2.5 Storyline 3: New pipeline (see Figure 3.17)

Instead of using existing pipelines, a 48-inch new pipeline - which will be future proof e.g., can handle more than 12 GW – is installed. This new pipeline transports pure hydrogen and connects the Dutch Continental Shelf with other regions.

The pipeline might be necessary by 2035, operating at fractional capacity at the start. As H2 production capacity increases over the years, the pipeline operating capacity will rise toward design capacity. Such an operating philosophy requires a long-term investment strategy including cost-sharing and tariff setting for the production side/market side. Large scale offshore pure H_2 storage will happen in the salt structures present in the offshore Hub North region.

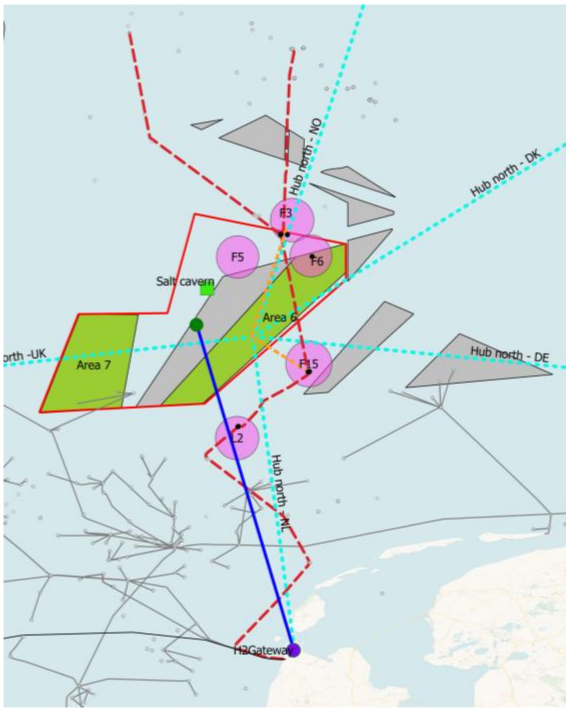

Figure 3.17: Overview of storyline 3

3.5 Interconnected hubs

So far, the hub storylines were discussed in isolation. However, since large part of offshore infrastructure (such as pipeline and electricity transport network) will span through all the three hubs, it is essential to consider interconnection between the three hubs. Doing so helps not only in optimising design and operational conditions for the offshore infrastructure, but also share the capital and operating expenses. To explore this possibility, we have combined the individual storylines from hub West, East and North to represent the interconnected hubs. The 'Integrated Hub Storyline 1' is obtained by combining the 1st storyline of hubs West, East and North. Similarly, 'Integrated Hub Storyline 2' and Integrated Hub Storyline 3' are defined. The assumptions and considerations listed for the individual storylines are considered applicable in the interconnected hubs storylines.

4 Methodology

4.1 Model Description

The working of the model used to analyse the technical and economical parameters of the storylines is described in this section. Figure 4.1 shows the flowchart of the model denoting the various stages of the analysis. Further details on the underlying logic of the model can be found in Appendix A.3.

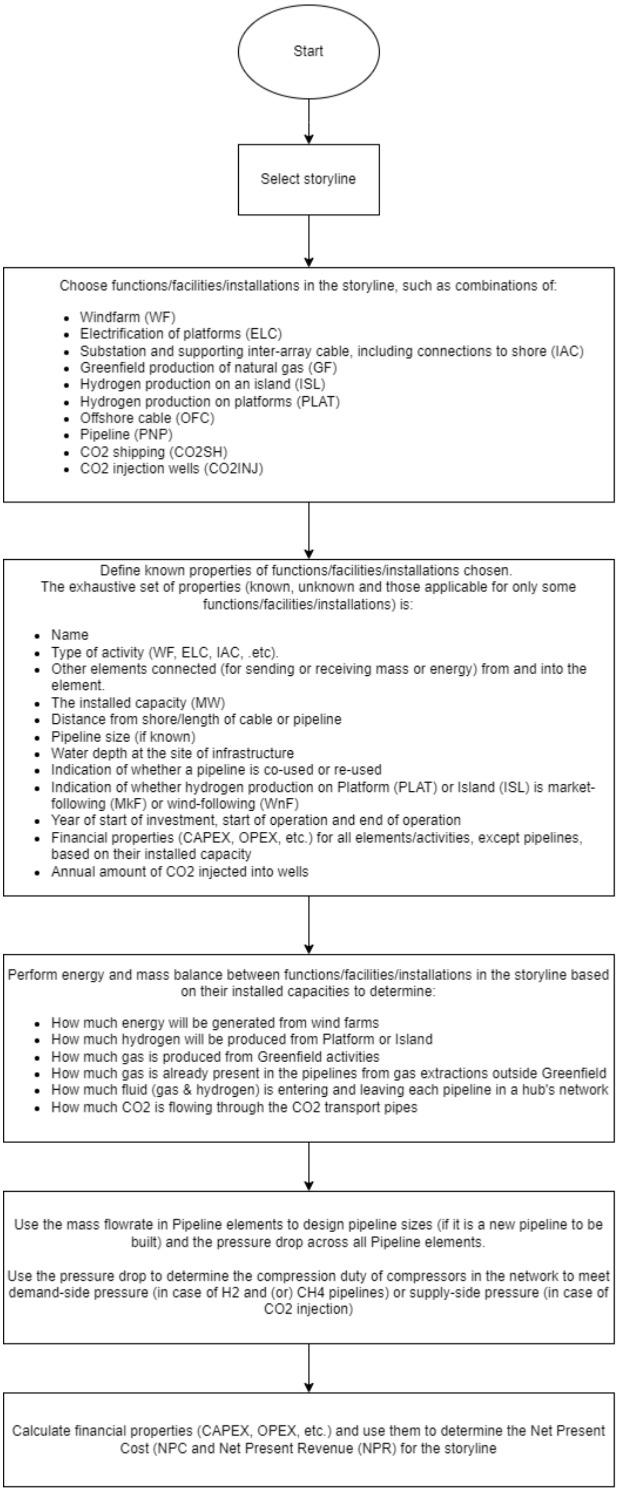

Figure 4.1 Flowchart depicting techno-economic calculation workflow for hub storylines.

In the first stage, the model begins by selecting the hub storyline under consideration. For each hub storyline, the model inputs the functions and facilities that are part of the storyline. Appendix A.1 gives the list of the functions that are a part of each hub storyline while Appendix A.2 gives an indicative timeline of the initial investment and operational lifetimes of the functions. The detailed logic of the techno-economic modelling is explained through a flowchart in Appendix A.3.

In the next stage, the model gathers the known properties of each of the function, facility and installation: This may be technical data (like the installed capacities, where the hydrogen is produced (platform and/or island), connection types, distances to shore, sizes of pipelines, etc.) or financial information the timing of investment and operations. The model also calculates financial information such as the CAPEX and OPEX for facilities/functions whose financial calculations can be performed with the known properties that have been gathered in this stage.

For further details of the wind profiles and other technical parameters for offshore wind, see Section 3.2.1 and Appendix B.1; for details of platform electrification, see Section 3.2.2; Section 3.3.1 and Appendix B.5 offer detailed technical and other parameters for inter-array cabling. Details of greenfield natural gas production can be found in Section 3.2.5. Details of the components of P2G systems can be found in Appendix B.4, electrolyser parameters in Section 3.2.4 and details of wind-following and market-following electrolyser modes are provided in Appendix B.2.1 and B.2.2, respectively. The parameters of Island or Platform configuration used in the P2G system can be found in Section 3.4 and Appendix 3 and 7. Details of offshore cabling can be found in Section 3.3.1. Section 3.3.2 provides information on pipelines and routings for each energy hub with re-use and co-use of pipelines for different uses described in Appendix B.6.3. Injection of CO_2 is detailed in Section 3.2.3 as well as in Appendix B.6.

Next, the model conducts an Energy and Mass Balance analysis to determine the quantities of energy and commodities produced. In this stage, the model determines:
- The quantity of energy produced from wind farms
- The quantity of hydrogen produced on platform and/or island
- The quantity of natural gas already present in the pipelines from sources other than greenfield production
- The quantity of fluids (hydrogen and natural gas) entering and leaving each pipeline in the hub network

The next stage of the model involves using the mass flow rates determined in the previous stage to design pipeline sizes and pressure drops across all pipeline elements. The pressure drops calculated are used to determine the compression duty for the compressors in the network to meet the demand-side pressure requirements (of hydrogen and/or methane pipelines) or the supply-side pressure requirements (when CO_2 injection is considered in the storyline).

In the last stage of the analysis, the model uses the Energy and Mass Balances and the financial parameters to calculate the CAPEX and OPEX of the storyline which are further used to determine the final output of the model, namely, the Net Present Cost (NPC) and Net Present Revenue (NPR).

The subsequent sub-sections give a detailed description of the functions, facilities and installations that are considered in the hub storylines.

4.2 Description of functions, facilities, and installations

This sub-section discusses the facilities and installations considered for the defined offshore system integration options, including Offshore wind, Electrification, CO_2 injection and storage network, P2G network and Greenfield natural gas production.

4.2.1 Offshore wind

Wind profiles were examined for various wind areas for the year span of 2014 – 2018.[3] All profiles show the typical behaviour of maximum production during the winter months, gradually decreasing towards the summer and climbing again during the fall. Important to note is that year-on-year deviations in the period of 2014-2018 were in the order of 4 to 5% (see figure below). The profile of 2017 was chosen as this was within the timeframe chosen the most average year.

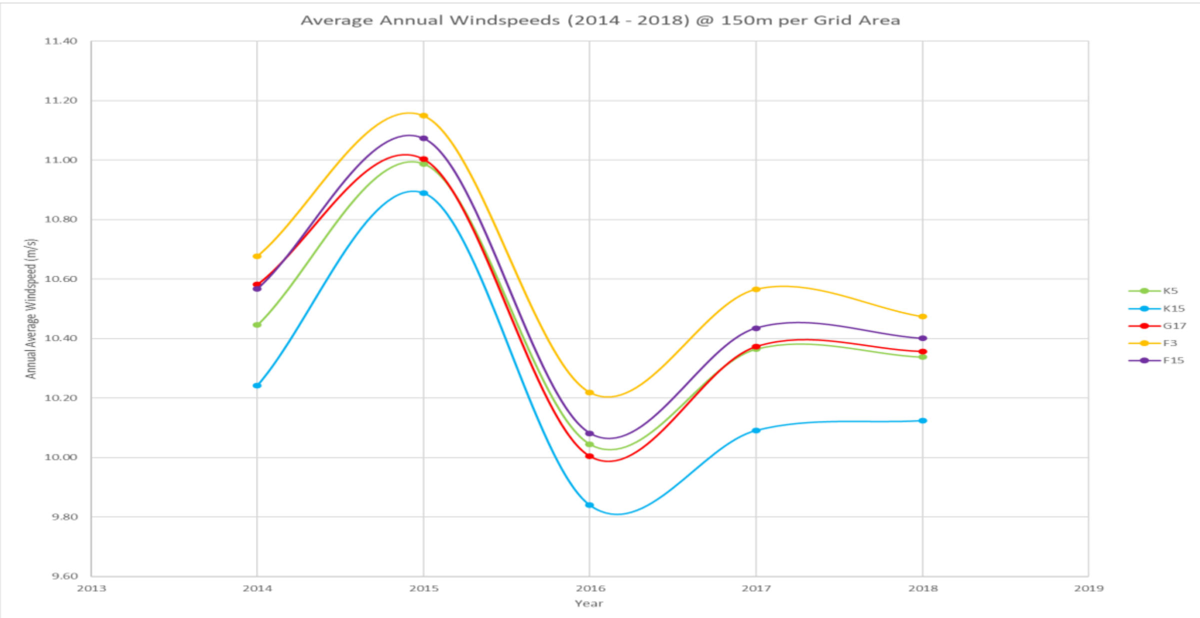

Figure 4.2: year-on-year variations in wind speeds

Upscaling present wind turbine technology to 2025, 2030 and beyond, we follow the approach of Bulder et al. on potential cost reductions for offshore wind energy (16). Wind turbines will continue to increase in nominal power, the assumption is that in 2025 it will be possible to build a wind turbine with a rotor diameter of 250 m with a nominal power of 15 MW. By 2030, it is assumed that a wind turbine with a nominal power of 20 MW with a rotor diameter of approximately 290 m will be feasible. The key parameters of these technologies considered in the report are summarised in Table 4.1.

[3] This data was taken from the Royal Netherlands Meteorological Institute (KNMI) for locations with actual mast data for greater accuracy. Data was taken for a mast height of 150 m at an hourly resolution, and converted to power by applying the power curve of an assumed future wind turbine technology. Coordinates for measurement (Latitude – Longitude): Area 1 (K5): 53.7 – 3.33, Area 2&8 (K15/L10): 53.24 – 3.99, Area 5 (G17): 54.04 – 5.41, Riffgat (N5): 53.90 – 6.28, Area 6 (F3-B): 4.41 – 54.58, Area 7 (F15-FA): 4.49 – 54.11

Table 4.1: technical parameters (data taken from (16))

Wind turbine		2020	2025	2030
P_{nom}	MW	10	15	20
D_{rotor}	M	193	250	290
H_{hub}[1]	M	126.5	155	175
Rotor PD	W/m²	342	306	303
RPM_{min}	RPM	3.5	2.7	2.3
RPM_{max}	RPM	8.4	6.5	5.6
Economic lifetime		20	25	30
Farm area	km²	125	67	100
Yield	TWh/Y	3.5407	4.7775	9.4704
Farm efficiency		0.913	0.875	0.86
Availability		0.974	0.974	0.976
CAPEX	M€/MW	2.43	2.55	2.57
OPEX	M€/MW/year	0.085	0,070	0.054

Due to the ongoing developments in turbine technology, the nature of the true power curve for the turbine was obtained by using the key parameters highlighted above, by upscaling the parabolic fit for the Siemens Gamesa 7 MW, and by calculating a range of values for the rated windspeed and confirming the value with TKI wind op zee (20). The actual curve fit is given in Equation 1.

$$W_{\text{turbine}} = \frac{W_{\text{nominal}}}{ws_{\text{rated}}{}^{3.33}} \times ws^{3.33} - 45 \sin \varphi$$

$$\varphi = 0.743172 \times ws - 1.33434$$

Equation 1: Power curve for turbines installed at future wind farms.

Where, W_{turbine} (kW) is the turbine power output, W_{nominal} (kW) is the nominal power rating of the turbines, ws_{rated} (m/s) is the rated windspeed required for attaining nominal power, and ws (m/s) is the wind speed. The above equation is valid for wind speed $2.5 \leq ws \leq 10$. When the power is below the cut-in speeds (below 2.5 m/s) or above the cut-out speed above 28 m/s the power produced is dropped to zero. For $10 \leq ws \leq 28$ the power equals the nominal power rating of the turbine.

The above methodology yielded a capacity factor of 58%, 55,6%, 55.6% and 57.2% for Area 1, Area 2 & 8, Area 5, Area 6 & 7, respectively. This is deemed to be in close agreement to the expected result. The values for a single turbine were scaled linearly to the size of a wind farm. Losses are considered by adapting the profile with farm efficiency in addition to the availability of the wind farm.

The power curve is also adapted to existing wind parks – such as Gemini and Riffgat – to reflect their realised operational conditions. The actual curve fit for existing wind farms – like Riffgat – is adapted by downscaling the parabolic fit by altering W_{nominal} and ws_{rated}. SWT-turbine technology with a nominal power and rated windspeed of 3.6 MW and 12 m/s is applied to reflect power outputs of the existing Riffgat windpark location.

The power curve for existing wind farms yielded a capacity factor of 41% for the Riffgat area. This is in line with public findings on expected yield, not yet considering the wake losses and efficiency losses.

4.2.2 Electrification

Electricity could be used to power offshore platforms and to replace the existing use of gas to power the various processes. Previous work suggested that electrification of offshore gas platforms can result in higher efficiencies, lower overall greenhouse gas emissions, and result in higher reliability and longer maintenance intervals for offshore installations (17). The value of electrification for the involved stakeholders and specifically the business case for some gas platform operator has been analysed in NSE 1 and NSE 2. The specific capacity and costs applied in these studies will, after validation with the operators, be incorporated into the analysis. The aim is to coordinate the integration of the required electricity network with nearby power requirements from other energy-use functions. Platform electrification can only be ratified in two situations. First, electrification benefits should outweigh the cost related to the needed investments. Existing natural gas production platforms might be too close to their cessation of production date, due to the relatively low gas-in-place, to recover the initial investments. In contrast, for similar reasons, the electrification business case of green field developments seems promising. An operator may still decide to go ahead with the investment decision even though the direct benefits do not outweigh the costs. Operators argue that the value of electrification becomes positive when the electricity network can (at a later stage) be used for the P2G process (second situation). Electrification will not take off when no P2G is planned around a platform location. In this case, the electricity demand for carbon storage will occur under decentralized RES production around the platform location. The electricity is expected to be provided with diesel generators, but further analysis will be performed to indicate decarbonisation strategies for the CCS injection process.

The electrification of a (gas) production platform consists of the following parts:

- (Re)placement of the current installed gas turbines used in mechanical trains such as compressor trains
- Integration of auxiliary power requirements in power distribution
- Cable connecting the gas platform with the substation
- Offshore grid connection to landfall location with required compensation

By replacing a gas turbine drive with an electric drive train, the drive-related CO_2 and NOx emissions are eliminated, because the completely combustion-free electric powered drive train generates no emissions whatsoever on-site. There is also the profit from significantly higher efficiency. The entire electric drive train has an efficiency rate of up to 96% and therefore consumes far less energy than a gas turbine drive. Electric drive train also involves many financial benefits. Due to emission-free technology, CO_2 taxes, permits, or carbon offsets are avoided. Higher efficiency, lower energy demand, and temperature fluctuation stability reduce energy costs. Maintenance costs are minimized because general overhauls are usually not necessary for 20 to 25 years. The inspection and service during this time period can be performed on-site and requires only a few days of shutdown during the drive train's lifetime.

4.2.2.1 Standalone electrification

Offshore electricity consumption may also take place without having a connection to the offshore transmission system. The electricity will be provided by offshore renewable production sources such as wind, solar and/or wave. The challenge is however to provide a continuous supply of power – and given the intermittency of the above resources – an offshore back-up system is required. In this case we consider lithium-ion battery options as well as back-up provision by a fuel cell. Lithium-ion batteries are commercially used in a variety of ways, from electric vehicles to residential batteries to grid-scale applications. For this offshore purpose, a battery size up to 10 MW and 10hr of storage capacity is considered to cover the hourly variation in production. The battery system can also be used to support a black start of the offshore equipment.

In addition, fuel cell technology is back-up to support continuous supply across seasons. Compressed hydrogen tanks are most appropriate from a techno-economical point of view. They are suitable for high cycle operation and provide short to medium term storage services ranging from hours to months. A typical unit consists of a rack of tanks able to store 500 kg or, equivalently, 16.7 MWh[4] of hydrogen at 200 bar and atmospheric temperature. Investment cost of compressed hydrogen storage tanks include purchasing cost of the tank and cost for installation and both scale with the amount of hydrogen (kg or MWh) that can be stored.

Table 4.2 summarizes the main techno-economic assumptions considered for standalone electrification. The capacity required to support a continuous power supply will vary with resources and consumption considered.

Table 4.2: Main assumptions for standalone consumption[5]

		Assumption	Source
Wave energy	investment costs	5.65 MEUR/MW	(18)
	O&M	0.15 MEUR/MW/a	
	Load hours	4658 hours	(19)
Solar energy	Investment costs	675 €/KWp	(20)
	Fixed O&M	14.75 €/KWp/a	
	Var O&M	0.0019 €/KWh	
	Load hours	900 hours	(21)
Battery (Li-ion) (10 MW – 10 hr)	Investment costs (excl. grid integration)	2445 – 2696 €/kW	(22)
		244.5-269.6 €/kWh	
	Fixed O&M	6.9-7.1 €/kW	
	Variable O&M	0.46 €/kWh	
Fuel cell (100 MW – 10 hr)	Investment costs fuel cell	900 €/kW	
	Investment cost inverter	40.5 €/kWh	
	O&M	3%	**assumption**
Compressed Hydrogen Tank	Investment costs	535 €/kg	(23)
	OPEX	3%	

4.2.3 CO_2 injection system

The development of a central CO_2 network is the epicentre of the Hub West scenario. Carbon storage activities take place at all key platforms in each storyline by re-using the existing gas production platform for injection. Wherever possible, inter-field pipelines in Hub West are re-used for CO_2 transport. An annual CO_2 storage profile can be established based on the CO_2 sources available from industry and the CO_2 storage potential for the individual fields. The relevant storage parameters considered are kept constant for all storylines for Hub West (see

Table 4.3). The effective storage capacity considered per cluster have to be validated with the current operators. The first estimation is based on public announcements by the operators, data from previous

[4] The volumetric density of hydrogen compressed at 200 bar and 273°C is 15.6 kg/m3 or 520 kWh/m3 (Lower Heating Value)

[5] Conversion rate of 1$ to 0.9€

NSE reports (19), and other public data (28) (29) (10). The indicative timeline for CO_2 injection activity in the Hub West region considers the start and duration of injection per cluster as well as the expected annual 3.5Mton/CO_2 of storage capacity required by 2050 (based on II3050).
CO_2 injection activity is expected to start around the L-blocks, considering the expected End of Life being around 2023-2027 (7), and subsequently injection activity in the K15 and K14 clusters will follow soon. Capex investments are scheduled in the year prior to installation, whereas installation should be planned 6 years in advance. The network extension, in the case of new pipelines, toward K5 is scheduled for 2033, and injection will start in 2034 with a max. plateau injection rate of 3Mton/a. Up to 2060, some 650Mton of cumulative CO_2 are expected from the IJmuiden and Rotterdam region (18). Additional CO_2 sources can be expected from blue hydrogen production located in coastal regions or via shipping from the UK, Belgium, France, or Germany.

Table 4.3: carbon storage parameters for platforms considered for carbon storage

	Effective storage capacity (Mton)[6]	Start date of injection[7]	Initial well pressure considered [Mpa]	Technical max. Reservoir pressure [Mpa]	Plateau injection rate (Mton/a)[8]*	Power demand for injection (26)	Overall Complexity and Risk (6)
K15	115	2029	2.5	40	6	100 kW	Low – multiple fields and aging infrastructure, but low well integrity risks; single operator and well-known geology
K14	50	2027	1,5-5	40	5	5.1 MW	
K5	120	2032	2.5	40	3	2.1 MW	Low – multiple fields, but relatively modern infrastructure; late availability allows learning from earlier projects
K8	156	2030	2.5	40	5	100 kW	Moderate – multiple fields and ageing infrastructure, but relatively few blocks account for most capacity; several old, abandoned wells
L10	140	2026	2.5	40	6.5	1.1 MW	High –abandoned wells, aging installations, some fields in cluster already almost depleted

* Note: the injection rate will not be constant over time. The reflected injection rate is the max. injection rate used to calculate the required equipment duty.

CO_2 transport from the connecting areas onshore to Hub West is expected to take place through a new pipeline. CO_2 transport by means of shipping is studied as an alternative. The base-case for injection is reflected in Figure 4.3.

[6] The first estimation is based on public announcements by the operators, data from previous NSE reports (19), and other public data (29) (10) (28)

[7] End of Life dates from Next step decommissioning scenarios. Assumed start of injection dates are: 2030 (k15), 2032 (k14), 2026 (L10), 2034 (k5)

[8] The first estimation is based on public announcements by the operators and other public data (19).

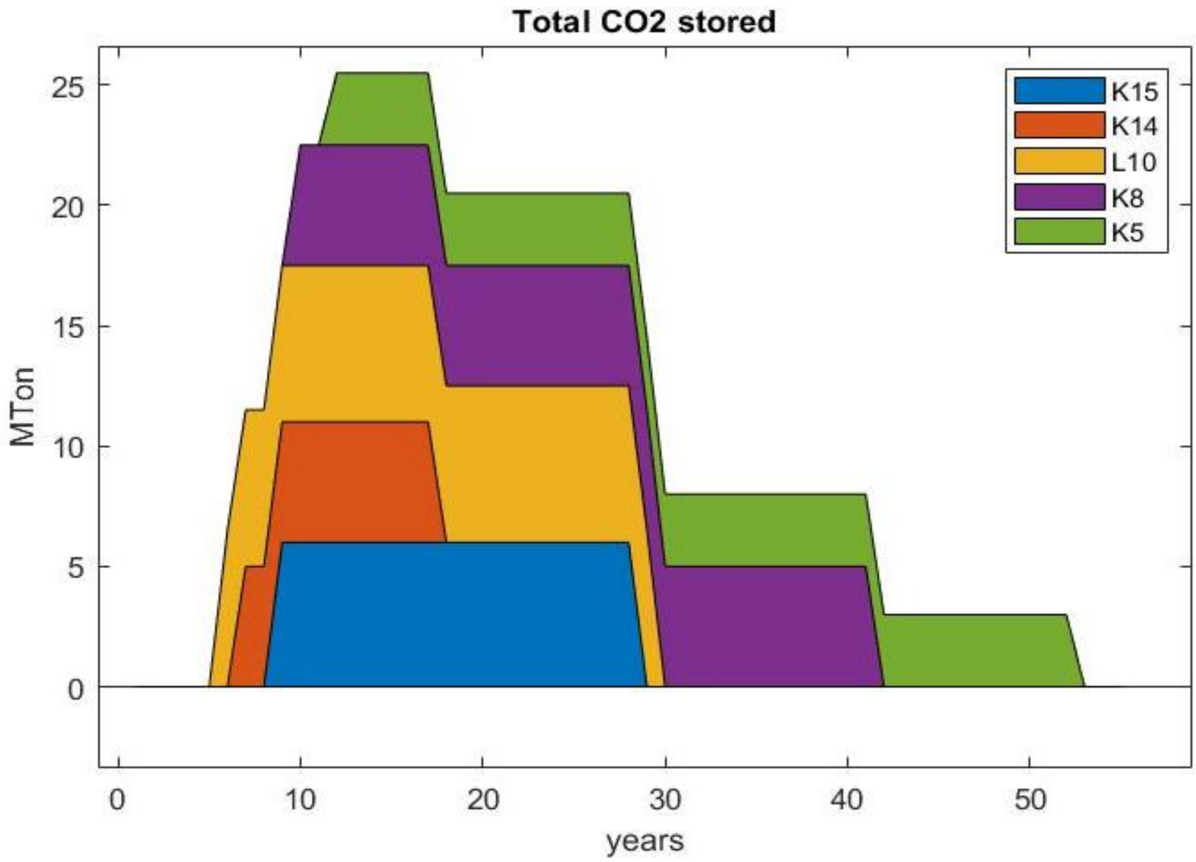

Figure 4.3: Indicative timeline for CO_2-injection activity in selected K/L cluster

Investment costs

The techno-economic analysis comprises of onshore compression requirements, transport infrastructure, CO_2 injection requirements on all clusters considered, as well as potential platform refurbishment needs. The scope boundary is the existing wellhead. The conditions of the wellhead (and other subsea equipment), the possibility to be revised and the related costs are outside scope. All techno-economic considerations regarding the compression and transport network are discussed in section 3.3-.3.1.

IEAGHG conducted a review of CO_2 storage costs which emphasised large differences in cost of storage. The main differences in cost were related to: field location (higher cost offshore than onshore), field knowledge level (high for depleted hydrocarbon fields, leading to lower costs; low for saline aquifers, leading to higher costs), existence of re-usable infrastructure (wells, offshore structure), reservoir capacity (higher cost for smaller reservoirs) and reservoir quality (injectivity; higher cost for poorer quality reservoirs) (27).

Overall, the cost estimates documented by IEAGHG vary from to €6-20/tonne CO_2 stored for the most expensive option (offshore saline aquifers). We assume a relative CAPEX of 7M€ per well workover which is in line with Cranberry (32). When CO_2 arrives is in the gas phase, an offshore compressor is required for compression, but when CO_2 arrives in the liquid/dense phase, a pump can be used to boost the pressure level (32)[9]. The variable operating cost comprises of the power needed to run the offshore compressor / the pump and a seawater resistance unit. At closure, the injection wells and offshore

9 We assumed that the 'cut-off' pressure for switching from a compressor to a pump is the critical pressure of CO_2, which is 73.8 bar.

structure (where appropriate) are decommissioned. At a later stage, usually in the post-closure phase, monitoring wells (if any) are also decommissioned. Based on a review of CO_2 storage costs decommissioning costs are assumed to be ~15% of the associated CAPEX (31). In order to decommission a site, a final seismic survey is needed to meet the regulatory requirement for mapping the CO_2 plume in the reservoir, including a history match of the reservoir model and predictions for the fate of the CO_2 in the reservoir. However, decommissioning procedures for CO_2 storage sites have yet to be established.

4.2.4 Hydrogen network

Figure 4.4 shows offshore hydrogen network connecting the offshore power to gas production in hubs West, East and North.

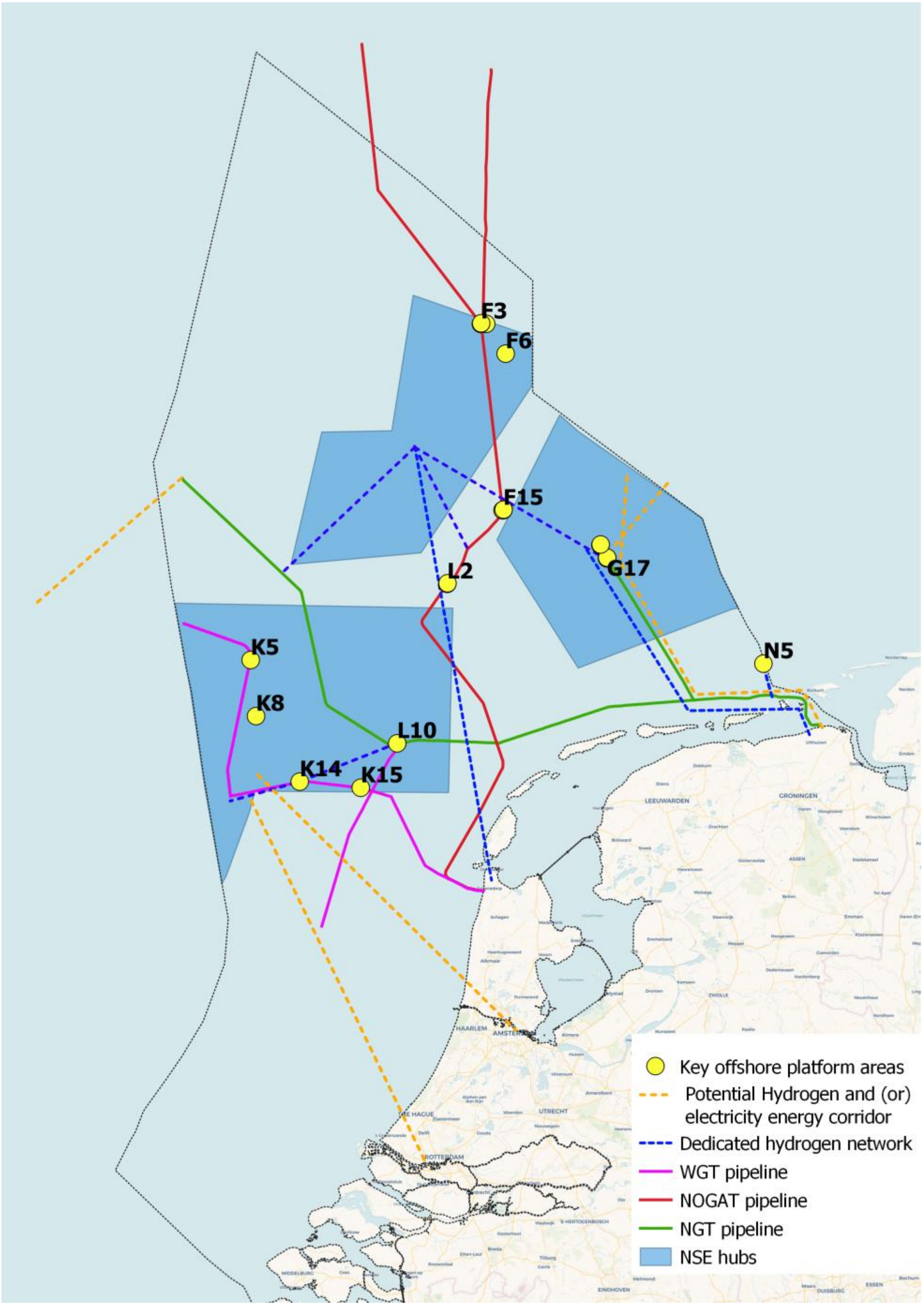

Figure 4.4 Offshore hydrogen transport network across hubs east, west and north

4.2.5 P2G system

This paragraph describes the necessary elements of the hydrogen production facility, considerations, and assumptions for this production facility. The functional and operational parameters were obtained from data from the literature (BOP). The stack represents the core of the system where electrochemical reactions take place. The "balance of plant" (BOP) is composed of several subsystems that provide secondary functions in the electrolyser system. The major subsystems in the BOP and key parts in each system include:

- Power supply: AC/DC rectifier, DC voltage transducer, and DC current transducer.
- Deionized water circulation system: circulation pump, piping, valves and instrumentation, and controls.
- Hydrogen processing: dryer bed, hydrogen separator, tubing, and valves and instrumentation.
- Cooling: plate heat exchanger, cooling pump, valves and instrumentation, and dry cooler.
- Miscellaneous: compressed air valve, ventilation, and safety requirements (combustible gas detector and exhaust ventilation).

Appendix 7.4 describes the design considerations for a 500 MW production platform in further detail.

4.2.5.1 State-of-the-art versus future design approach

PEM electrolyser technology is currently not commercially available at large scale. Current public data is limited to 10 MW scale1. However, the consortium is aware of several innovations that will have an impact on the design of the offshore hydrogen system. Non-public data from a non-commercial model of Siemens – with a capacity of 32 MW - was retrieved and used for the pre-liminary design of a 500 MW platform. This section will describe the impact of these innovations on the design of the platform and highlight the potential design consequences.

Efficiency & impact on cooling

Table 4.4 shows that innovation is expected regarding the efficiency of PEM electrolyser systems, which has a significant impact on the required cooling capacity. Based on commercial technology, e.g., a nominal efficiency of ~72%[10], around 140 MW_{th} heat needs to be removed by cooling. There are some additional components that need cooling (e.g., rectifiers), and therefore around 190 MW_{th} cooling capacity is expected for the complete plant. Expected innovations are focussed towards increasing the efficiency of the PEM and all auxiliary equipment. The 78% of efficiency measured at the DC input connection of the PEM at the beginning of life. However, uncertainty exist on the development of the efficiency over the lifetime of the PEM stacks, for instance, technical assessment by TU Delft shows that cell-efficiency of a 10 MW electrolyser unit drops by almost 3.5% over a 5-year duration (33). Therefore, additional space might need to be reserved to accommodate higher cooling capacities.

Table 4.4: Comparison state-of-the-art versus future approach

	Current technology available on market (ITM commercial)	Expected impact innovations (Testing phase Siemens)
Efficiency PEM (Nominal)	72%	78% [11]
Efficiency system (Peak), without desalination	62%	75.6%[2]
Equivalent Thermal energy output (nominal)	140 MWth	110 MWth
Equivalent Thermal energy output (Peak)	190 MWth	125 MWth

[10] LHV

[11] The EoL Scenario is assumed 10% less than the BoL (set to 78%), and so in worst case the rest would leave as heat, which needs cooling.

ΔTemperature (ΔT)

Table 4.5 shows that additional innovation is expected regarding the allowable inlet and outlet temperature of seawater, which have a significant impact on the duty of the seawater pumps. The impact of a higher ΔT on the degradation and lifetime of the system in the long run needs further investigation.

Table 4.5: comparison state-of-the-art versus future approach (ΔTemperature)

	Current technology available on market (ITM commercial)	Expected impact innovations (Testing phase Siemens)
Inlet temperature (sea)water	50°C.	30°C.
Outlet temperature (sea)water	55°C.	60°C.
ΔTemperature	5°C.	30°C.

There are two ways of cooling PEM stacks. The electrolyser can either be cooled through excess process water (via demi water installation) or by separate internal electrolyser cooling circuit (a secondary flow). Each system has its own advantages and disadvantages. However, the ΔT cannot be too high if the PEM-system is cooled via excess process water. If the stacks are cooled by process water only, the flow through the stacks is huge. Hence the whole platform needs to accommodate huge pipelines and pumps in between the stacks. The separate internal electrolyser cooling circuit can handle a higher ΔT. The advantage of a higher ΔT is that the whole platform can accommodate much smaller pipelines and pumps in between the stacks. The spatial impact can be further reduced when using a separate cooling circuit, which is however, not yet a common easy design for electrolyser manufacturers. The choice of design will affect the flowrate of cooling water as well process water. For the future design approach, a ΔT of 30℃ chosen. Though, a strong remark must be given that it is uncertain when such system becomes commercially available and what the impact would be on the degradation and lifetime of the system (30). Furthermore, many cell properties like activation overpotential and ohmic resistance are temperature dependent and large temperature gradients across the cell ΔT (>$10oC$) will therefore result in nonhomogeneous loading of the cell (31). Hence, future research is required to indicate whether process water cooling systems can actually handle this higher ΔT.

4.2.5.2 Operational specifications (base assumptions)

Wind turbines installed around the platform vicinity are feeding electricity into the electrolyser package. The wind park is assumed to produce enough electricity to power electrolyser system and the platform with installed capacity of 500 MW per platform. The operational hours of electrolysis unit will depend on the wind park availability as well as the location of the wind park. The wind developments in the hub sections are discussed in the storylines. The electrolyser operating mode is flexible load with minimum load 15%. In case of dedicated hydrogen production, the wind park operator has no option to sell its power to the electricity market. The electrolyser operator and the wind farm operator are totally dependent on each other; thus, it is expected that they will set an internal contract price for all electricity consumed. In contrast, market following hydrogen production implies that short term production decisions are determined by market opportunities, more specific when electricity prices are below the benchmark price for hydrogen production (see also Appendix B.2).

4.2.5.3 Investment costs

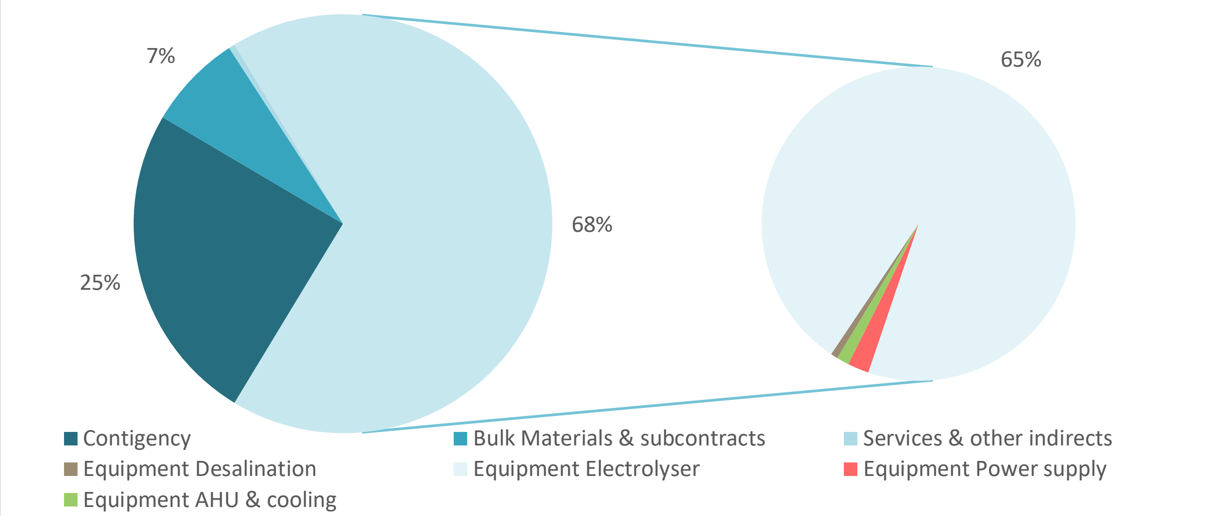

Figure 4.5: Investment costs distribution 500MW system

Investment costs for a 500 MW offshore power-to-gas systems, comprising of the above-described components are in the order of 635M€. This is a +/- 40% estimate. Electrolyser stacks, in the order of 750 €/kW, are responsible for about 65% of the total investment costs (see alsoTable 4.4). The cost estimates are based on current price levels.

4.2.6 Greenfield natural gas production

Green field natural gas development is at the base of the Hub East and Hub North storylines. Natural gas plays an important role in the transition to a fully sustainable energy supply in 2050. Dutch gas is preferable to importing foreign gas. Because Dutch natural gas is cleaner, cheaper, it makes our energy supply more independent from abroad (13).

Gas extracted from green fields must meet certain specifications of the trunklines. Local pre-treatment is a requirement if the extraction facility cannot be connected to nearby offshore treatment facilities. This is for instance the case for N05-A. The N05-A platform will therefore be designed as a gas treatment platform, which will then be connected to the NGT pipeline with a newly constructed pipeline. The new pipeline will have a length of approximately 15 kilometres and the route of this new pipeline may run over a length of less than one kilometre through the Natura 2000 area of the North Sea Coastal Zone. In case of F05-A & F05-B – located in proximity of Hub North – an interfield pipeline connects the extraction field with the central production platform F3.

N05-A platform will be designed as a combined gas extraction and treatment platform with a capacity of at least four million cubic meters of natural gas per day, which is in line with the One-Dyas objective (32). Gas transmission companies require that the impurities, such as hydrogen sulphide (H2S) and carbon dioxide (CO_2) are removed. In addition, natural gas produced from a well is usually saturated with water vapor. The water vapor itself is not objectionable, but the liquid or solid phase of water that may occur when the gas is compressed or cooled is troublesome. Liquid water accelerates corrosion of pipelines and other equipment; can allow the formation of hydrates that can plug valves, fittings, and sometimes the pipeline itself. Removal of the water vapor by dehydration eliminates these possible difficulties and is normally required by gas sales agreements (33).

Rough numbers are presented for the expenses involved in setting up green field gas production (and treatment) facilities. The capital costs cover the well cost, construction of the platform and treatment facilities and all auxiliary services. Drilling costs vary according to drilling depth, water depth, rig type and distance from shore and are assumed a daily rig rate of 130.000€ and average operation time of 30-35 days (32)[12]. In addition, auxiliary devices – such as fuel gas treatment – are in the order of 10M€. The fixed operational expenditures of exploration and coverage of auxiliary services are estimated at 0.02 EUR/Nm3 to 0.09 EUR/Nm3 (32)[13]. Table 4.5 illustrates the capital cost related to the development of the N5 exploration and production facility – summing up to some 175M€. Costs for electrification, compression, pipeline transport as well as structure costs are not yet included.

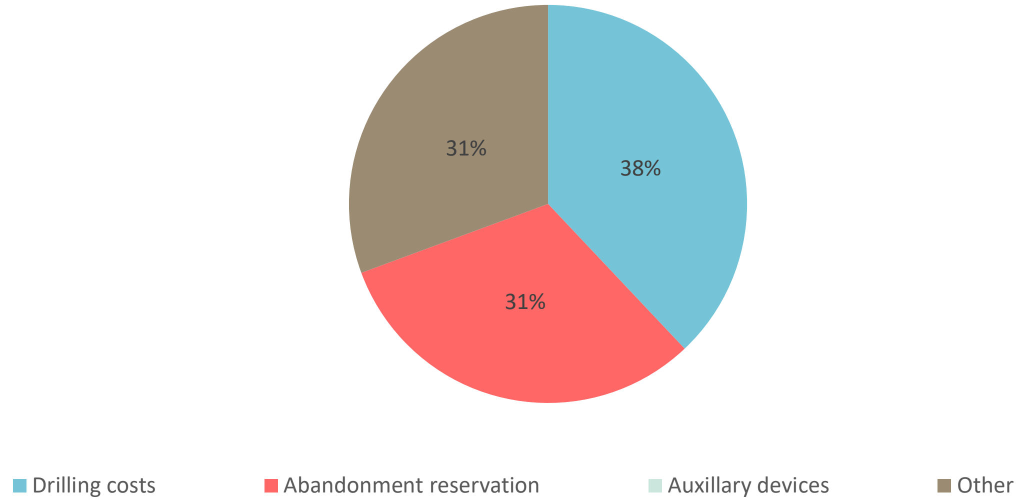

Figure 4.6: Investment costs green field development (N5 – 13 wells)

4.3 Description of infrastructure

4.3.1 Transmission / interconnection

The technology decision for transmission infrastructure is highly dependent on the future locations for offshore wind. The wind tendering areas around Hub West are likely to be connected via HVDC transmission lines following the technology decision made for the IJmuiden-Ver region. For the same reason, the technology decision for Hub East is less certain, given that both the Gemini wind park and the planned wind park Ten Noorden van de Wadden are still connected with alternating current (AC) (38).

Table *4.6* shows an overview of the cable designs for the two technologies. The total generation of energy has been considered, in combination with expected future developments regarding cable technology. TNO has developed a dedicated offshore energy transport model (TOET) to make a cost-optimization on cable costs given a certain technology, distance, and volume of energy. For both HVAC & HVDC power transmission systems, sub-components such as cables, inductors, transformers, offshore platform, etcetera were identified. For each sub-component, costing data were sourced from public & proprietary

[12] This number does not include material costs and chemical logistics to the field.

[13] Some 3% of the capital investments of auxiliary services

sources available in the Eefarm database[14]. The costing data was fitted to a linear or quadratic polynomial and included within the offshore energy transport model as cost functions. The cable procurement has been validated with design and cost estimations of export cables provided by Boskalis. The land-fall locations have been discussed within the consortium and are for a great extent in line with the landfall considerations of the by Guidehouse and Berenschot in 'Systeemintegratie wind op zee 2030-2040' (39).

4.3.1.1 Routing Hub West

220 kV - HVAC transmission system		
Island/platform	**Transmission infrastructure**	**Onshore substation**
Transformer costs (step up from 66kV to 220kV) Switch gear costs Installation costs	HVAC cable costs (procurement) HVAC cable laying costs and losses Reactive power compensation costs	Transformer costs (step up from 220kV to 380kV) Switch gear costs Installation costs

525 kV - HVDC transmission system		
Island/platform	**Transmission infrastructure**	**Onshore substation**
Transformer costs (step up from 66kV - 525kV) Converter costs (AC-DC) Installation costs	HVDC cable costs (procurement) HVDC cable laying costs and losses Reactive power compensation costs	Transformer costs (step down from 525kV to 380kV) Converter costs (DC -AC) Installation costs

Figure 4.7: Overview of electric system components for techno-economic analysis available in ToeT

Boskalis subsea cables made a design and cost estimation for two export cable installation scenarios in Hub West: scenario I: Export cable from area 1 to a shore landing near IJmuiden (some 210km and 15 crossings) and Scenario II: Export cable from area to a shore landing near Maasvlakte (some 250km and 25 crossings). The cable distance is about 25%-30% higher than the shortest distance measured between two points due to rerouting for instance. Appendix B.5 contains the budgetary proposals for the scenarios.

The figure below displays the cable costs considered per region. All wind regions are located at a distance of 150-250km from shore resulting in relatively high cable costs for HVAC systems. Total costs for export cables are slightly higher for going to the Maasvlakte area, which is logical considering the longer distance and the additional crossings required. In general, HVDC cable costs including installation and project management costs, lie around ~€1400 per km per MW for 525kV. The combined substations –

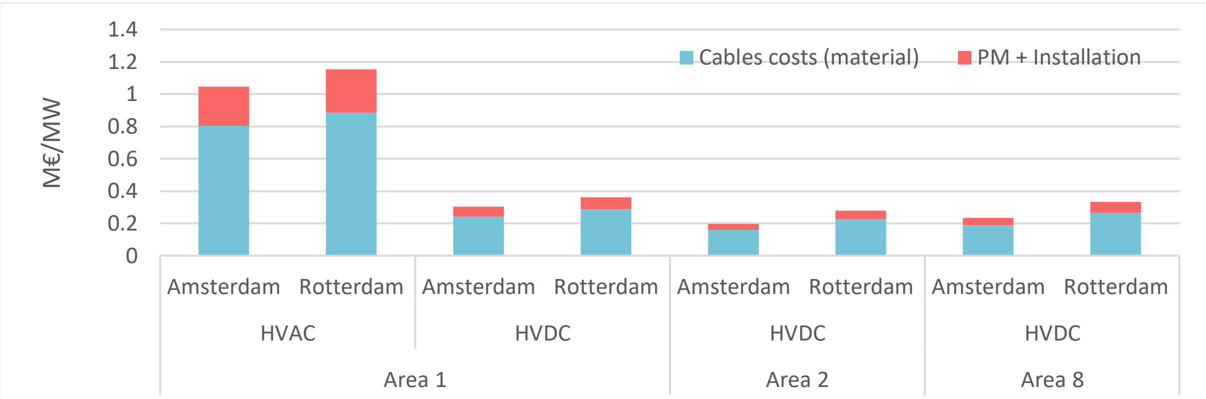

Figure 4.8: Cable supply and installation costs Hub West

[14] TNO & TU Delft developed the Eefarm program for the electrical and economic evaluation of different electrical layouts & concepts for offshore wind farms

transformer and converter – accumulate to some M€0.6/MW. Project management, insurance, installation etc. accounts for some 25% of the total cable costs

4.3.1.2 Routing Hub East

The national electricity grid in the north of the Netherlands offers extra capacity (up to 10 GW) to feed in electricity from the wind at sea (39). However, the national electricity grid does not have to be the limiting factor for landfall in the Northern Netherlands. Spatial and social aspects (including offshore) also play an important role. A specific challenge for onshore connection is the fact that all transport connections have to cross the Waddenzee area, which is a well-protected nature area. During the first elaboration of routes, Royal HaskoningDHV analyzed the possibilities for a 6.7 GW to be constructed in one corridor comprising of 3x 2 GW HVDC, 2x 350 MW HVAC and potentially a H2-pipeline (40). Table 4.8 summarized the results of a 2 GW HVDC cable. Boskalis subsea cables made a design and cost estimation for a 2 GW HVDC cable from area 1 to a shore landing near Eemshaven (some 160km and 10 crossings). The cable distance is about 25%-30% higher than the shortest distance measured between two points due to rerouting for instance. Appendix B.5 contains the budgetary proposals for cable installation, including provisional sums for Boulder Clearance, Dredging and Crossings. The total CAPEX for a 2 GW cable is set at about 1.8B€. Cable installation accounts for some 25% of the total cable costs

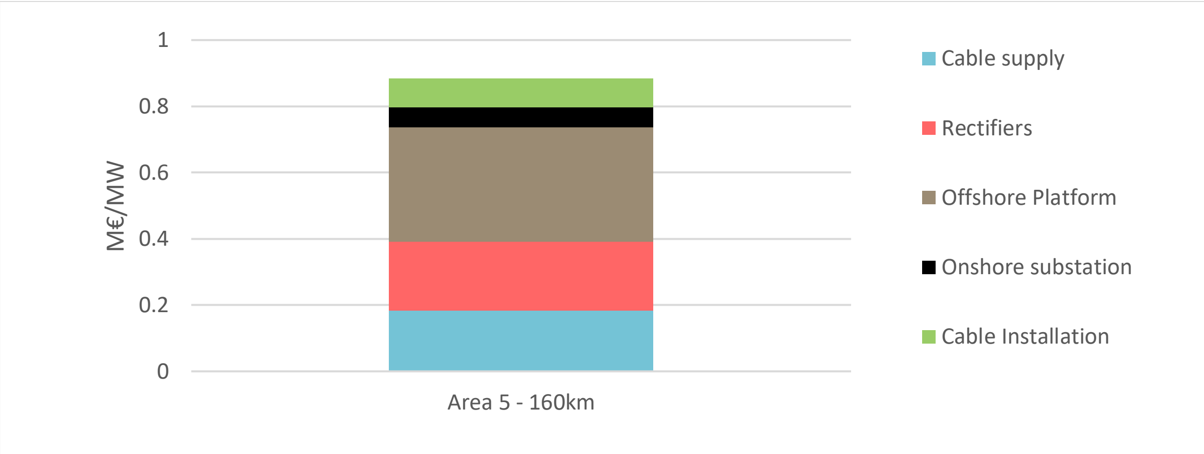

Figure 4.9: 2 GW HVDC network and cable installation costs Hub East

4.3.1.3 Routing Hub North

Boskalis subsea cables also made a design and cost estimation for HVDC export cable installation scenarios in Hub North: scenario I: HVDC Exports cables from area 6&7 to a shore landing near Eemshaven (some 1420km in total and allowance for 11 crossings per circuit) and Scenario II: HVDC Export cable from area to a shore landing near Den Helder (some 1120km and allowance for 7 crossings per circuit). The cable distance is about 25%-30% higher than the shortest distance measured between two points due to rerouting for instance. Appendix B.5 contains two budgetary proposals for both scenarios.

The figure below displays a budgetary indication for the HVDC network cost considered per region. All wind regions are located at a distance of 170-290km. The installation costs for export cables are slightly higher for going to the Eemshaven area, which is logical considering the longer distance and the additional crossings required (some 12-30% dependable on location). However, these numbers do not consider further in shore landfall of cables. For instance, Guidehouse and Berenschot assume that the landfall in Den Helder will take place in Middenmeer, about 20 km southeast of Den Helder (close to Gasunie location Wieringermeer on the hydrogen backbone) (35).

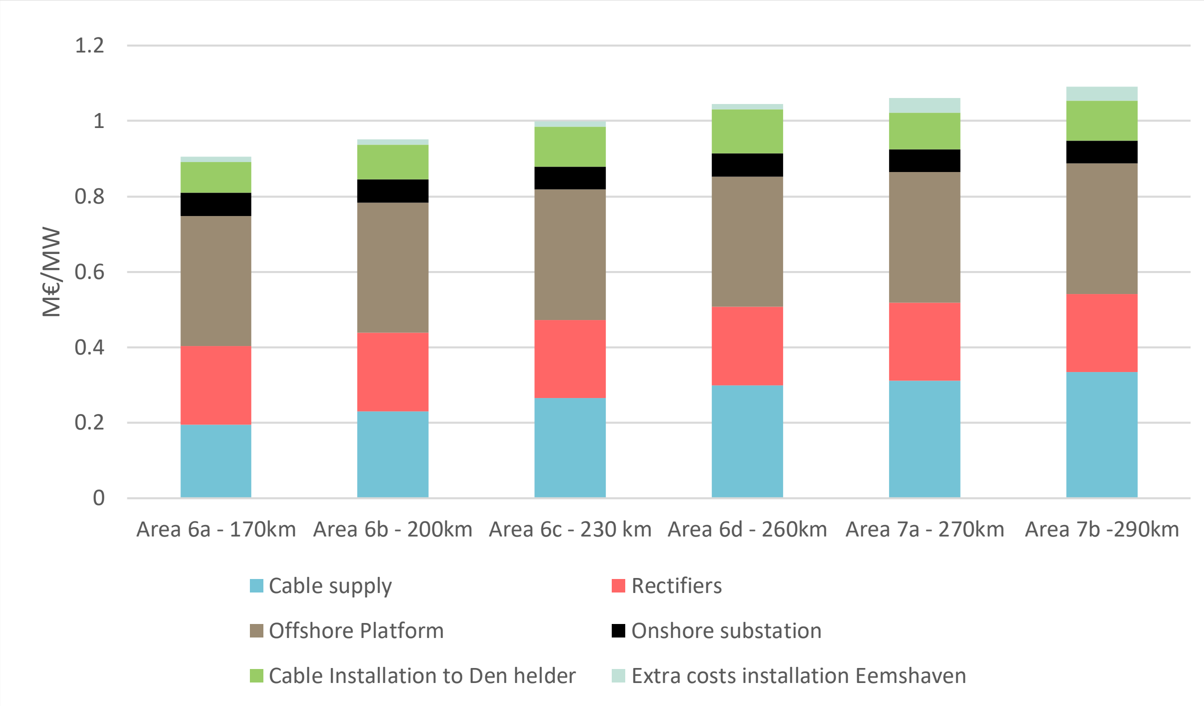

Figure 4.10: 2 GW HVDC network and cable installation costs Hub North

4.3.2 Pipeline transport

This section shows trends, requirements and corresponding costs when assessing a combined natural gas, CO_2, and hydrogen transport network. Existing transport infrastructure can positively support system integration in the selected regions, by reducing cost (incl. installation cost), potentially reducing the impact in ecology, and accelerating the pace in which system integration can take place. Table 4.6 summarised the capacity of the existing main trunk lines, which sets the upper limit for co-and re-use.

Table 4.6: Capacity existing offshore pipelines (7)[15]

		Capacity			
		CH_4	CO_2 – liquid	CO_2 – gas	H_2
	Energy hub	GW	MT/y	MT/y	GW
WGT	West	11.6	54.4	15.4	13.8
NGT	West, East, and potentially North	11.6	54.4	15.4	13.8
Nogat	North	11.6	54.4	15.4	13.8
Local	West	5	23.4	6.6	5.9

Pipeline transport options considered in this study are indicated in Figure 4.11. For offshore pipelines, a firmer view on timelines is needed based on forecasts on gas transport profiles, preferably provided by the main trunk line operators. If these forecasts could not be provided, a less accurate annual transport profile is established by considering the annual production volume of all platforms connected and the

[15] Natural gas: P = 80 barg; T = 10 degC; velocity = 5 m/s, Hydrogen: P = 100 barg; T = 10 degC; velocity = 20 m/s, CO_2: P = 70 barg; T = 10 degC; velocity = 3.2 m/s

expected end of life of the associated platforms. The transport profiles are analysed on an annual basis by altering the volume of gas transported due to the inclusion of green field CH_4 developments. However, these transport flows are less accurate, since production volumes are estimated on past values rather than forecasts (e.g., current gas price peak is not considered). Once transmission of natural gas has stopped, re-using a pipeline for CO_2 transmission is given priority due to the relatively high share of CO_2 transport cost in the overall unit technical costs for CO_2 storage and the specific technical requirements needed for CO_2. This implies that when re-use for CO_2 is considered, the pipeline may not available other purposes. More insight on the usability of existing infrastructure for CO_2 transport is gained via desktop research and discussions with pipeline inspection experts and pipeline designers. The following sections discuss the co-use, re-use, and new pipeline scenarios for all hubs combined.

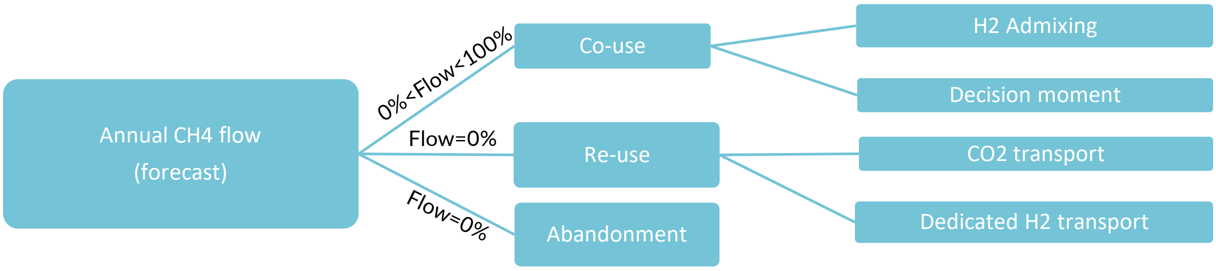

Figure 4.11: Decision tree co-use and re-use existing trunk lines

4.3.2.1 Co-use - admixing

DNV GL together with Gasunie Transport Service (GTS) have investigated to what extent the existing gas infrastructure could be used, considering the security and stability of the network. They concluded that GTS's existing high-pressure gas network offers excellent opportunities for transporting either a 100% hydrogen stream or a natural gas-hydrogen blend [7]. According to the DNV GL study, there are two main limitations when trying to mix hydrogen with natural gas. The first one is due to legal requirements, that determine a maximum 2 vol% restriction of hydrogen into the Netherland's high-pressure natural gas transport system. The capabilities of existing end-user equipment form a second limitation leading to recommendations to keep hydrogen concentrations below 2 vol% of the total gas stream. For new sophisticated equipment this fraction could be up to 15% to 20% (41). Whereas the latter limitation is inspired by equipment use at the end point of the gas value chain, the limit might not be relevant to the purpose of pure transportation activities [7]. Considering the technical feasibility of blending the hydrogen with the natural gas stream at the injection point, measures may need to be taken at the extraction point to separate both gases, but 'filtering' the hydrogen from the natural gas is costly and requires additional energy. Another aspect that could pose problems is the highly variable gas quality, which is the combined effect of i.e., the filtering and variations in the flow rate throughout the entire year. In addition, a study by the Fraunhofer Institute found that significantly higher GHG emission reductions can be achieved through direct application of hydrogen in transport sector and industrial applications versus blending of hydrogen in the gas mixture (42). They also found that 5% H2 blending is a no regret option towards 2030, though the approach to blend hydrogen from 0% to 20% in existing grids represents lock-in effects as area wide adaptation measures would have to be financed that are neither necessary nor sustainable for the long term (24). Blending of hydrogen into the existing offshore trunk line can be considered if the full capacity of the pipeline is not used. To what extent admixing will be considered will depend on four main parameters: the annual flow of natural gas transported by the trunk line, the prospective of new CH_4 extraction activities, the prospective of hydrogen production activities connected to the trunk line, and the allowable percentage of hydrogen admixed. The specifications at landfall will define whether the requirements for admixing are exceeded, potentially leading to investment in new infrastructure or other measures. An estimation of blending profiled for the

NGT and NoGaT are depicted below. The profiles are based on max. load of the offshore hydrogen facility (so in case of high wind speeds). The time-window for admixing in the WGT/Local is rather small, and thus admixture in those pipelines is not considered

NGT

The NGT seems to be a feasible candidate to bring hydrogen ashore by blending it into the natural gas flow. The 36-inch pipeline runs through hub West and hub East – collecting the hydrogen – and bringing it ashore in Uithuizenmeden. The profile (see Figure 4.12) indicates that the capacity of the pipeline would be sufficient to accommodate the blended substance, though due to the decline in natural gas production and the increase in hydrogen production, the proportion of hydrogen to gas increases rapidly over the years. As far as the admixing transport modes is concerned, admixing up to 15% should pose no integrity or safety issues on Dutch gas pipelines (43). The capabilities of existing end-user equipment form a second limitation leading to recommendations to keep hydrogen concentrations below 2 vol.% of the total gas stream. Although, legally constrained, if the offshore gas grid (partly via the onshore grid) is connected to industries that are able to cope with higher hydrogen concentration, the technical constraint might be eliminated. Another possibility is that onshore gas streams, for instance coming from onsite green gas injection facilities, would raise the proportion of gas in the transmission network, reducing the relative share of hydrogen blended into the substance. Additional research would be required to identify what possibilities are available at the Uithuizenmeden landfall site. For now, we expect additional measures to be required by 2028. Such measures can delay the development of large-scale hydrogen offshore, installing Steam Methane Reforming (SMR) or Autothermal Reforming (ATR) facilities onshore, and/or installing Pressure Swing Adsorption (PSA) units to separate the substance. Additional considerations for the technical design of the PSA unit are described in the technology brief on H_2 infrastructure (40).

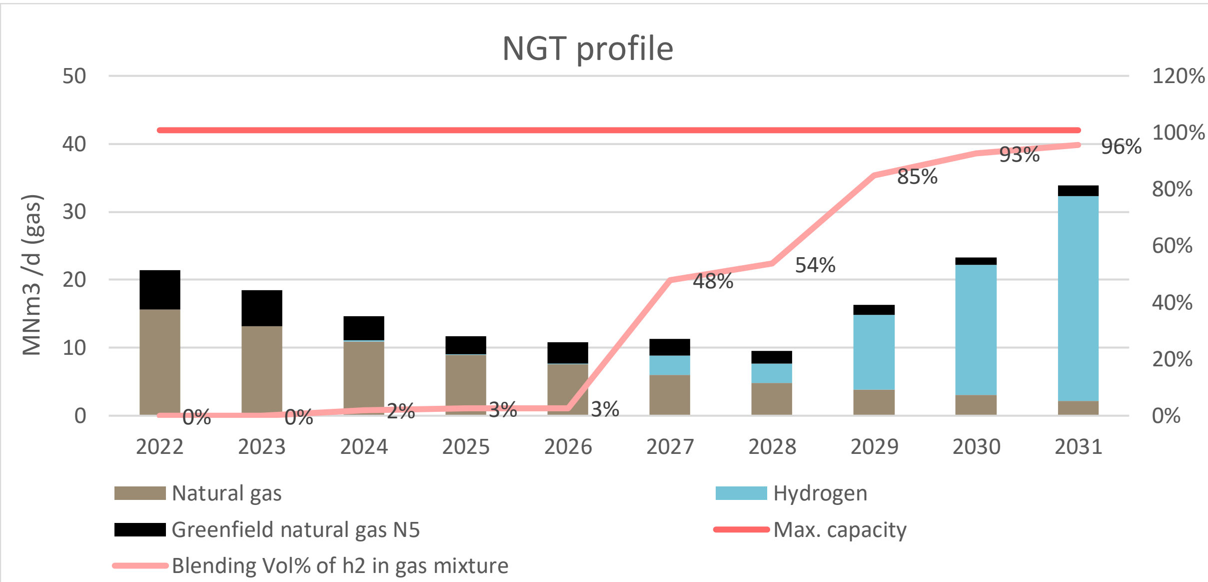

Figure 4.12: NGT - blending H2 into gas mixture. By 2031, about 10 GW of hydrogen can be transported by the NGT pipeline.

Nogat

The NoGaT seems to be a feasible candidate for bring hydrogen produced in the Hub North region ashore by blending it into the natural gas flow. The profile (see Figure 4.13) indicates that the capacity of the pipeline would be sufficient to accommodate the blended substance, though due to the decline in natural gas production and the increase in hydrogen production, the proportion of hydrogen to gas increases

rapidly over the years. The requirements and conditions for allowing the blending of hydrogen are similar to the case described above.
The plans to realise a blue hydrogen production facility at the landfall location (Den Helder) could facilitate the blending of hydrogen, such that the hydrogen concentration is kept below 2 vol% of the total gas stream. Additional insights into whether the foreseen capacity of the blue hydrogen facility could accommodate these blended streams is required.

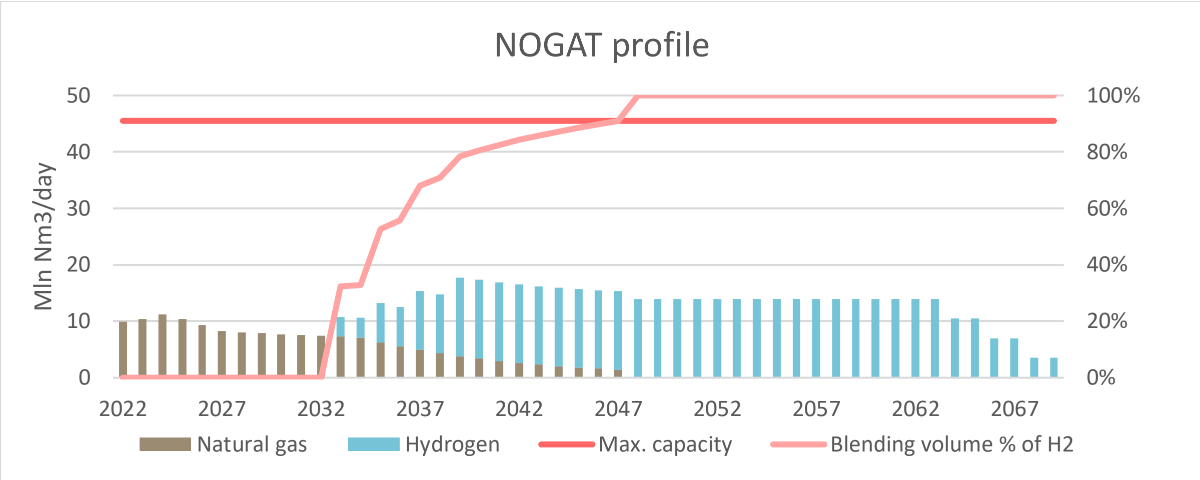

Figure 4.13: NoGaT - blending H2 into gas mixture. The profile comprises of some 8 GW of H2 capacity, and excludes future greenfield development.

Re-use (Retrofitting existing pipelines)

A major concern with the re-use of existing pipelines is that these pipelines have been in operation for a large number of years (up to 45 years) already and have not been designed for indefinite use, but rather for the expected lifetime of the natural gas production. As the unprocessed fluids from gas and oil wells contain (formation) water, CO_2, H_2S and other corrosive substances, the question is whether the pipelines nowadays are still suited for hydrogen (which, in general, requires specific materials) at elevated pressures or CO_2 transport. To answer this question, a detailed inspection of the pipelines is required. However, this is hampered by several complications. The first complication is that the corrosion, which will have taken place over the years, varies strongly across the circumference of the pipeline. Due to gravity, the water fraction tends to be higher near the bottom (the 6 o'clock position) than elsewhere. As the corrosive substances are hydrophilic, the corrosion will be more severe near the bottom than elsewhere. Therefore, the inspection tool should be able to detect such position-dependent corrosion. A second complication is the possible occurrence of pit corrosion. Although it may not reduce the average thickness of the pipe wall, the local thickness can be reduced significantly and can lead to a fatal failure like a rupture.
The third complication is that the pipeline systems use a multitude of internal diameters. This is because wells have different production rates and so the diameter increases downstream to keep the velocities more or less constant with decreasing pressure and the use of trunk lines, in which the production of different wells and fields is commingled to simplify the transportation to shore. Therefore, the fluids from a well pass through a large number of different diameters before reaching the shore. Therefore, a number of important requirements for an inspection tool, which should be able to determine the integrity of the pipelines under study, needs to be fulfilled:

- It should be able to measure the corrosion rate around the complete circumference of the pipeline with a high angular resolution.

- It should be able to measure the corrosion rate with a high spatial resolution.
- It should be able to detect pitting corrosion, which can occur at any position at the circumference of the pipeline.
- It should be able to inspect the above-mentioned corrosion types when the internal diameter of the pipeline changes (in general, increases in the downstream direction).

The unambiguous determination of the integrity of the pipelines to be reused with Hydrogen or CO_2 is key. On the one hand, blowouts would be a serious risk related to injection of hydrogen, on the other, it would also hamper the operation of a hydrogen system as certain pipeline sections can no longer be used. This specific risk might not apply for CO_2 but for this commodity other risks (due to corrosion for instance) might be more considerable. If ruptures would occur too often, the reuse would be jeopardized and the whole existing pipeline system will be abandoned and scrapped. Subsequently, a new system needs to be installed, but this cannot be done overnight. Many strategy options and investment decisions depend on the outcome of the proposed inspections.

A separate problem is the external condition of the pipelines. Seawater is rather corrosive, and the question is how well the initial corrosion protection is still effective. So apart from the inspection of the interior of the pipeline, inspection of the exterior is also highly recommended.

More insight on the usability of existing infrastructure for hydrogen and CO_2 transport is gained via desktop research and discussions with pipeline inspection experts and pipeline designers. To do so data on (I) inspections of older oil and gas well flow lines on wall thickness (II) in homogeneities of wall thickness across the circumference due to corrosion, and (III) presence of pit corrosion and data on condition of the outside of the flow line in seawater, is analysed. In addition, discussion with experts on design rule for offshore flow lines for oil and gas wells, including corrosion and erosion allowance, should provide more insight on the issue of blowout of flow lines. It might be necessary to have some flow lines inspected 'as is' when no data from inspections is available by third parties.

4.3.2.2 New pipeline infrastructure

The infrastructure cost for new pipeline sections is retrieved by ToeT (see Figure 4.14 for an overview of the components included). The ToeT-model, and the variable input for the infrastructure calculations, will be validated via a stakeholder session with onshore and offshore pipeline operators. The ToeT-model is applied to the specific geographic regions by analysing possible trajectories. Experts from Boskalis' pipelaying department will support with advice on bending rates and the route chosen. Together with the Internal Survey Department of Boskalis, they will support further detailing of the routes, such that the ToeT-model can be updated with location specific information on the required routings and/or crossings. The onshore pipeline network is out of the modelling scope for all commodities; however, all gases should meet the onshore network specification at landfall. This implies that natural gas should be delivered at 68 bars while meeting the Wobbe-index, and that hydrogen should be delivered accordingly to the specifications coming from the market consultation currently performed by Gasunie. At this point we consider around 30 bars by 2030, and around 50 bars thereafter. The design considerations and routing approach taken (re-use focused or market-focused) for a joint offshore CO_2 network is elaborated in Appendix 7.6.

Natural gas transmission		
Platform	**Transmission infrastructure**	**Onshore/offshore**
Compressor (incl. efficiency, stages, power ratings) Platform tie-in	Pipeline costs (design flow, pressure, length, and material) laying costs (length, routing) OPEX (fixed/variable)	Tie-in in natural gas grid

Hydrogen transmission		
Platform / island	**Transmission infrastructure**	**Onshore/offshore**
Compressor (incl. efficiency, stages, power ratings) Platform tie-in	Pipeline costs (design flow, pressure, length, and material) laying costs (length, routing) OPEX (fixed/variable)	Tie-in in national grid, PSA (cleaning)

Natural gas transmission		
Onshore	**Transmission infrastructure**	**Offshore platform**
Compressor (incl. efficiency, stages, power ratings)	Pipeline costs (design flow, pressure, length, and material) laying costs (length, routing) OPEX (fixed/variable)	Platform tie-in, injection facilities, pump

Figure 4.14: Overview of pipeline components for techno-economic analysis available in ToeT[16]

4.3.3 Other Network Component costs

4.3.3.1 CO2 compression

The conditions of the NSE CO_2-network considered is designed to receive CO_2 streams from various projects (see also Appendix 7.6). Hence the network specification is based on the most lenient specification of and as such, the designed system network will not be a bottleneck in integrating the various CCS projects. The compressor station – located at each of the harbour locations - can operate in two modes, free-flow and pressurised. In free flow mode, the compressor station is bypassed, and CO_2 enters the offshore subsea pipeline at the operational pressure of the onshore pipeline (27 – 35 bara). In pressurised mode the CO_2 enters multiple parallel four-stage internally geared compressors. These compressors pressurise the CO_2 either to 60 bara and retain the CO_2 in the gaseous phase or pressurise it to 80-132 bara to operate the offshore pipeline in the supercritical/dense phase. Due to the multiple parallel compressors the compressor station can turn down from the nominal injection rate (1,750 t/h at Maasvlakte, 812.5 t/h at IJmuiden and 750 t/h at Den Helder) to the minimum injection rate 90 t/h. The internally geared compressors are equipped with interstage coolers after stage 1 and stage 2. To control the temperature of the CO_2 at the outlet of the compressors, all compressors are equipped with an after cooler. The interstage and after coolers are cooled with a closed cooling water (CCW) circuit. This prevents exposure to low temperature from direct seawater cooling. Low temperature would potentially introduce a two-phase flow inside the compressor for temperature below the critical temperature near the critical pressure, which should be avoided. The cooling water inside the CCW system is circulated by pumps P-001A-C/E and fed to the compressors at 25 °C. The cooling water returns at 35 and is cooled to the desired temperature in heat exchanger E-001A-C/E with seawater. An expansion vessel is installed to compensate the thermal expansion in the system. The seawater cools the closed cooling water by increasing the temperature of the seawater by 5 °C to a maximum of 25°C (in case the seawater is at a seasonal high of 20 °C). A combination of static bar screen and rotary band screen prevents unwanted suspended solids from entering the system. Other design and functional specifications of the onshore CO_2 compression systems can be found in Appendix 7.7

A Request for Quotation (RFQ) has been sent to MAN Energy Solutions, which is also the supplier for the compressor station of the Porthos project. Other equipment and the dimensions of the buildings are following the approach taken in the Porthos project. The estimated direct equipment costs are 185M€ with a +/- 40% accuracy (see Figure 4.15). Equipment (mostly compressors) comprise of the half of the costs. Operational expenses, mainly consisting of electricity uptake, are in the order of 50M€[17]

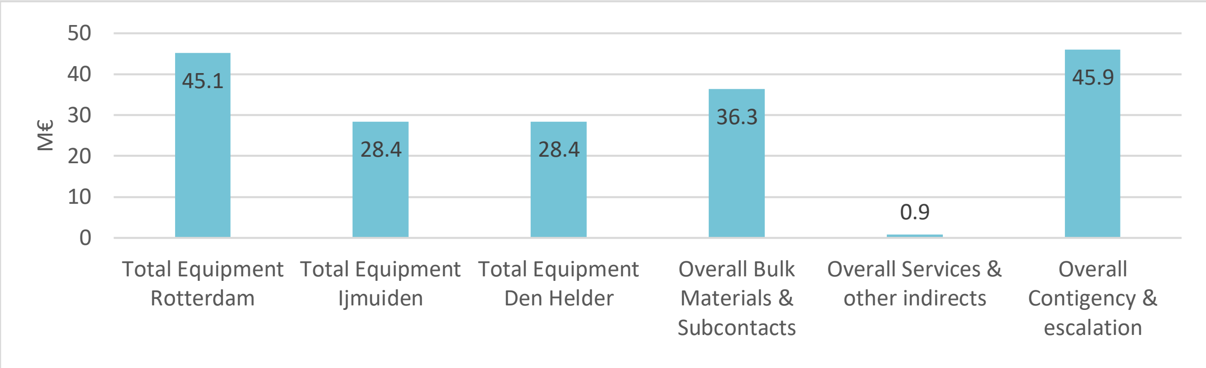

Figure 4.15: Total CAPEX for onshore CO_2 compression

Pressure drop across CO2 network

Figure 4.16 display the minimal pressure at each injection cluster considering the pressure drop across the CO_2 pipeline network. The figure on the left shows the minimum pressures if the fields are filled one after the other. The right figure shows the minimum pressures if the fields are filled all at once. The pressure-drop analysis confirms that, as long as the fields are filled one after the other, CO_2 arrives at the platform well above the critical pressure as indicated by EBN & Tebodin (41) which was set at a minimum pressure of 85 bara.

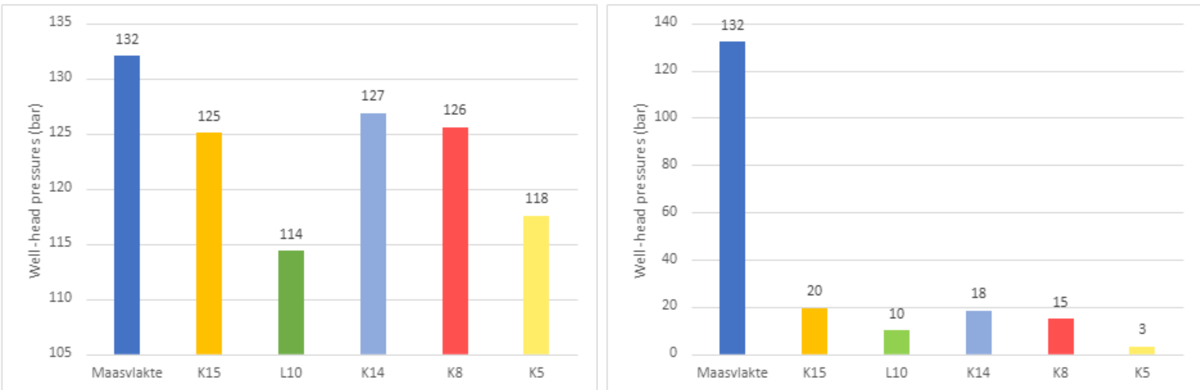

Figure 4.16: Pressures at injection clusters form the various locations, based on filling the gas fields one after the other (left) and filling the gas fields all at once (right)

4.3.3.2 CO_2 Shipping

Ship-based transport of CO_2 is considered as part of the offshore storage network discussed previously. CO_2 is shipped to an offshore offloading point close to the injection site and injection takes place via the existing platform, while no intermediate offshore storage is required (see Figure 4.17). CO_2

[17] Considering LCOE of electricity of 30€/MWh and compressor availability of 95%

processing takes place both on the ship and on the platform. The transport capacity ranges from about 3.3 Mtpa to almost 5 Mtpa, for a single injection well. Table 4.7 below shows the annual storage capacity of CO_2 in 80% depleted gas fields for depth ranges between 1km and 4km. Direct injection of CO_2 into a range of typical injection wells is feasible. Engineering and cost estimations, summarised in Table 4.8, are based on the CATO report "Transportation and unloading of CO_2 by ship - a comparative assessment".

Shipping represents a flexible alternative to pipelines for CO_2 transport and can be used to source CO_2 from smaller sources where constructing a pipeline may not be economically feasible, and can transport CO_2 to smaller depleted fields which are not accessible by pipeline. Shipping may prove to be cost-competitive with pipeline transport depending on the volumes being shipped and the distance of transportation. However, a detailed techno-economic study of the transportation of CO_2 using shipping-only solutions is out of scope for this study and remains a topic of further research.

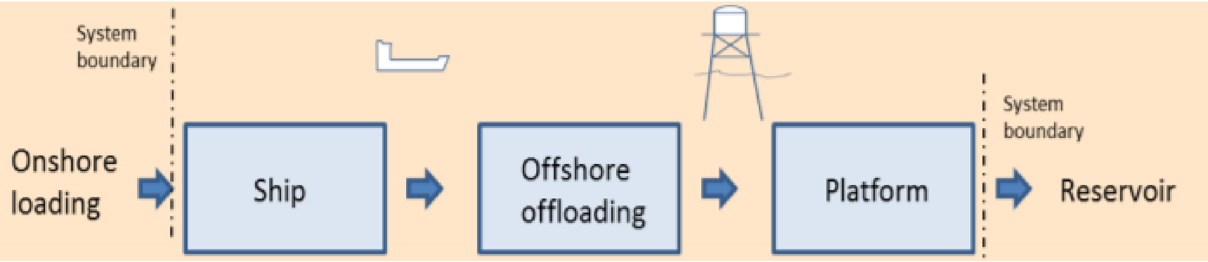

Figure 4.17: CO_2 shipping components considered (retrieved from (42)).

Table 4.7: Ship to platform and injection from platform parameters for 80% depleted gas fields (retrieved from (42)).

Scenario		A	B	C	D
Depth	M	1000	2000	3000	4000
Pressure reservoir	(bar)	20	40	60	80
Permeability	Mtpa	100	100	100	100
Injection pressure	Bar	238	300	300	250
Injection temperature	°C	23	12.5	10	10
Flow rate	Kg/s	150	136	122	106
	Mtpa	4.7	4.3	3.8	3.3
Pump capacity	MW	4.61	5.45	4.86	3.45
Total heating duty	MWth	16,96	13.75	12.34	10.72

Table 4.8: Cost estimation for CO_2 injection via shipping in depleted gas reservoirs using existing platforms for injection. Estimation based on a 20.000-ton carrier. (Retrieved from (46)).

	Transport distances up to 400km				Transport distances up to 800km			
Depth depleted gas reservoir (80%) (m)	1000	2000	3000	4000	1000	2000	3000	4000
CO2 transport cost (€/ton CO2)	14.9	16.5	18.2	20.7	18.4	20.2	22.3	21.3
Transport capacity (Mtpa)	4.7	4.3	3.8	3.3	4.7	4.3	3.8	3.3
Ships required	4	4	4	4	5	5	5	4
Utilisation factor (%)	65%	62%	58%	54%	70%	65%	61%	69%
CAPEX (M€[18])	372.3	372.3	372.3	372.3	447.9	447.9	447.9	372.3

4.4 Description of P2G structures

Hydrogen receives great attention in Europe. The European Commission's target to have 40 GW of electrolyser systems installed by 2030 will accelerate the development of electrolyser technology. Current technologies are in the scale of one to at most 10 MW and most of the technologies are delivered in a container. Innovations such as stacking the electrolyser cells or preparing the technologies for offshore application are novel. The sections below provide a first approach which will be under ongoing development in the NSE programme.

4.4.1 Hydrogen production platforms

The platform structure hosting all components described in 4.2.4 is expected to be 40 x 80 m and 10 m height and total weight is set at 9500 ton. Hence, spatial and height limitation exist at the offshore platform and therefore the spatial and weight footprint of the electrolyser must be as small as possible. This section describes the design considerations based on state-of-the-art electrolyser technology.

4.4.1.1 Single platform layout

Appendix C.4.3.5, summarises the various functional requirements related to the systems, provides a preliminary concept key one-line diagram, and a two-dimensional overview per platform deck. Auxiliary systems, like dryers, deoxygenators or compressors, are not part of the current design.

From the windfarms, the power comes with 66kV power cables to the platform and these are connected via 6 strings of each 90 MW capacity. There are three main power voltages foreseen:

- 66 kV for the incoming power from turbines and the power to the rectiformers,
- 10 kV for seawater lifting pumps
- 0,4 kV for the other pumps, backup power and auxiliaries.

The incoming cables are connected via 66kV switchgear to two large power transformers (66 to 10kV) and via the rectifiers (8 in total) to the electrolyser stacks. These electrolyser stacks are in pairs of four connected to a 1.8 MW fuel cell for emergency power. The two large transformers are placed on the second deck, straight above the incoming cables. The power transformed is fed 10kV MW switchgear,

[18] Includes ships (+/- 70m€ for 20.000 ton carrier), offshore infra (+/-110M€) and equipment (+/- 25M€), some €40 to 70M€ saving can be realised by using existing platform and reducing the need for a new standard offshore platform and installation of such platform (46 S. 39)

which, stationed on the first deck, and is connected to the variable speed drive H2 compressor, the two sea water lift pump motors, the oxygen motors and the two power transformers (10kV to 0.4kV). These LV transformers are connected to watermaker pump motors, demi water supply pump motors, intermediate cooling water pump motors, electrolyser transfer pump motors.

The auxiliary power system has been implemented redundant. If there is no grid connection to shore, all power required in the various standby modes have to be generated offshore. This will be done by a battery pack for instantaneous power requirements and preferably a fuel cell for longer durations. A fuel cell which consumes hydrogen and oxygen is preferred over the standard diesel generators: It omits the emission of CO2, and hydrogen and oxygen are readily available on the platform, while diesel would have to be shipped. The fuel cells are expected to run completely stand-alone, for example, it will have their own air cooling so cooling systems can stay offline during standby mode.

Most of the HV and LV equipment will be located on the lowest decks to reduce connection length. The lowest decks is also preferred because in case of a hydrogen leak the gas will float upwards. This way additional *ATmosphères EXplosibles* (ATEX) requirements can be circumvented. The switchgear, variable speed drives (VSD) and Uninterruptable Power Supply (UPS) equipment are placed in conditioned rooms (with overpressure).

On the second level the transformers and the rectifiers shall be installed combined with half of the electrolyser stacks. The electric equipment (rectifiers and transformers) requires serious cooling. While space is scarce, a central cooling will be applied.The transformers are located at the outside of the platform to facilitate cooling. The recti formers will be place at the sides of the platform. They will be (semi) open to the atmosphere to allow for natural cooling. This also allows for material handling if one of them fails. Underneath each of them a drip tray will be placed to collect any spilled oil in a non-flammable container in case of a transformer fire. The required ATEX zone is reduced significantly, as a result of the separation of the rectifiers from the electrolysers, which contributes to the operability and maintainability of the installation. The rectiformers on the third stack should not be placed directly above electrolysers due to possibility of hydrogen leakage.

For offshore operation, the amount of water required for electrolysis using desalination operation is given in the figure below. In order to make 100m3/h ultra clean water, initially 625m3/h will be required for the seawater lift pump, this can be reduced to 475m3/h since the 2nd stage RO Membrane flow can be recycled towards the feed flow of the 1st stage RO membrane. Based on an assumption of 60% flow brine & 40% clean water the overall numbers are indicated below. The discharge of brine solution is listed as a risk for the environment (see also WP4). Pre-mixing the brine solution with seawater before disposal minimize the environmental risk. Each watermakersystem consists of a cartridge filter, two RO membranes and two pumps. Due to the likelihood of failure a 5 + 2 configuration is chosen, so there is a backup available when maintenance is being performed.

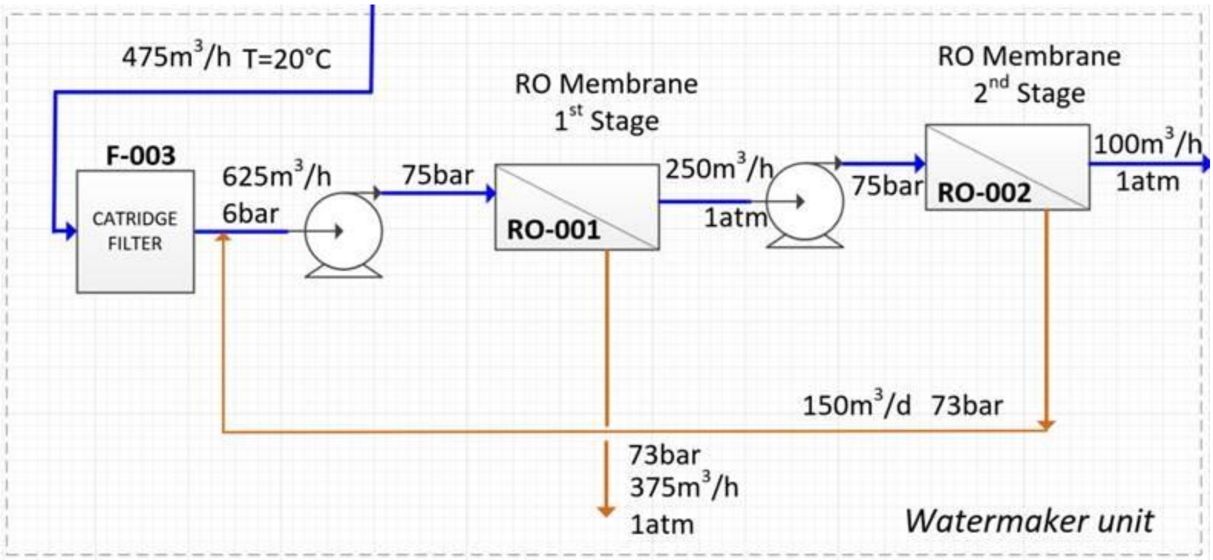

Figure 4.18: Process flow diagram of water maker unit.

The demi water supply loop is designed to provide demi water both for hydrogen production and for cooling of the stacks. During operation there is a constant flow in excess what is needed for the hydrogen production in order to cool the stacks. The demi water is supplied by the water maker system, which supplies it to a demi water storage tank which is used as buffer. A pump and an ion exchanger are then used to bring the water to the required pressure and purity. The water is supplied to the demi water loop via a feed vessel which also serves as an oxygen separator. The loop also contains a pump, a start-up heater, an ion exchanger and a heat exchanger. It is assumed the recti-formers are cooled as well.

In offshore applications (passive) air cooling of equipment is often preferred over seawater cooling when possible. While seawater cooling might offer savings in weight, it does require extra technical systems which need regular maintenance. For the design of this platform, we do choose for seawater cooling of the electrolyser stacks due the high cooling duty (100+ MW) required and the fact that a seawater system is already in place for the production of demi water for the stacks. Other main components which require cooling are the transformers and recti-formers. As their cooling duty is much smaller than that of the electrolysers, adding those to the seawater cooling systems would only have a limited impact. The glycol cooling system consists of heat exchangers, filters and pumps. Due to the likelihood of failure a 5 + 2 configuration is chosen, so there is a backup available when maintenance is being performed. Heat exchange sizes are calculated based on End of Life Scenario (See Appendix C.4.2.4). The EoL Scenario is assumed 10% less than the BoL (set to 78%), and so in worst case the rest would leave as heat, which needs cooling.

Venting of oxygen can safely take place at a height of 20m (see WP4 for additional details on technical calculations). Central venting of oxygen in the multi-platform configuration requires a heigh up to 200m. This is rather unlikely to happen at the offshore location as it may hamper the accessibility of the platform complex. Hence, further insights are needed to support the design of oxygen venting in multi-platform configurations.

Structural costs

Offshore platforms can be made of steel, reinforced concrete, or a combination of both, and can be used for many purposes. Selection of which type of platform to implement is highly dependent on the bathymetric characteristics of the location and the topside mass necessary to perform the foreseen energy function. Most common type of platform used in the North Sea are fixed platforms or jacket structures which will also be considered in this study.

Data regarding the CAPEX and OPEX of offshore oil platforms is very variable and difficult to pinpoint due to the extensive range of cost determinant factors (depth, location, platform type, function etc.). In addition, O&G and HVDC platform operators tend to keep this information confidential. DNV GL has made a high-level assessment for platforms housing high-voltage stations or power to gas components (47).

The surface required for new platform to facilitate hydrogen production are retrieved from the engineering designs provided by Bilfinger and IV, as discussed above. The mass of the topside for a single 500 MW platform is some 9500 tons and is summarised in the table below. The 500MW P2G platform at a water depth of 45 meters has a ball-park structure cost estimate of 161M€, excluding the equipment costs.

Table 4.9: 500 MW H2 platform weight overview and ball park estimate of structure costs

Topside		Gross Weight [MT]
	Architectural	1150
	Electrical & instrumentation	1780
	Mechanical	950
	Structural	5510
	Miscellaneous	110
Jacket	Substructure	6625
	Piles	3950
Total		**20075**

4.4.1.2 Multi-platform layout considerations

Several synergies can be realized when going from a single platform design to a multi-platform design configuration. A more optimal design – in terms of spatial use – can be realized by bridging the single hydrogen production platforms and centralizing part of the processes. Processes that can be centralized are electric services such as HV-transformers & HV-switchgears, hydrogen, and oxygen compressor systems incl. interstage coolers, discharge hydrogen vessels which are also acting as hydrogen compressor suction vessel, buffer storages, living quarters, control rooms, warehouses, and the helicopter pad.

Thereby the following considerations need to be considered for the layout:

- A more optimal design – in terms of safety – can be realized by separating the hydrogen and oxygen process (buffer vessels and compression units) as well as the position of the living quarters. H2 buffer and compression are placed at a central injection platform that is either positioned at the border of the platform layout or even at an existing platform just outside the P2G production region. The O_2 buffer, compression and living quarters are placed at another (venting) platform preferably at the opposite site of the hydrogen compression platform. Increased distance between the two injection/venting sites improves safety levels. Dual compression at stack-level to reduce need for O_2 compression needs to be further investigated as well as the possibility to vent/store O_2 in the seabed.

- A central platform will host all electric equipment. The size of this platform will depend on the required facilities, e.g., HVDC, HVAC, transformers, battery-back-up, DC-DC recti formers)
- Centralising part of the services has the advantage that electrolysers can be more condensed on the single production platforms. The expectation is that five to six production platforms would suffice to host 4000 MW of electrolyser capacity.
- A 500 m safety zone is expected to suffice (as in the case of TenneT transformer stations).

4.4.2 Structural design considerations for hydrogen production islands

This section describes the design considerations and related estimations of the cost of constructing an offshore sandy energy island in a specific geographic location. Island plot plans are constructed for the various geographic locations and the energy functions defined in the storylines. The methods for construction and accompanying figures for the various functions are described in Appendix 7.8.

The design considerations and related estimations of the cost of constructing is adapted to fit the specific geographic circumstances, considering water depth, wave heights, distance to shore, orientation (East-West positioning), and the scenario specific plot designs (see also Table 4.10). The size of the harbour (300 x 70 m) and the length of the breakwaters (1000 m). The total size of the different islands, the corresponding sand volume that is required and the length of the revetments is determined from the island plot plans.

Table 4.10: Specific geographic characteristics for energy islands

	Location reference	Distance to shore (km)	Water depth (m)	Function present[19]
Hub West	K08	110	~ 30	Dedicated P2G, With and without a harbour
Hub East	Borwin	120	35-40	Dedicated P2G
				Hybrid P2G

The design of the island in the Quick-scan Eiland op Zee serves as a basis for the CAPEX and OPEX estimations (44). To have a verified and executable design, an extensive study with model research, scheduling, risk analysis and such will be necessary.

4.4.2.1.1 Design considerations

Island structures can host various facilities. The inclusion of a sheltered docking facilities significantly affects the design, material need and thus cost. Appendix 7.8 comprises the design of both concepts for a sandy island construction in which the total surface available for P2G remains constant. The sheltered docking facilities provides however additional surfaces e.g., laydown area and warehouse to support O&M for offshore wind parks. The construction of breakwater - designed to break the force of the sea and to provide shelter for vessels lying inside – leads to more than a fourfold increase of Rock-use (type 0.3-1T), some 50% increase in X-blocks-units and in addition some 9 Caisson structures that support the docking of ships. The size of the harbour (300 x 70 m) and the length of the breakwaters (1000 m) have been chosen since this can be independent from the rest of the layout of the island.[17]

[19] Facilities, such as Heliport, Refuelling, bunker, (fresh) water and waste station, living quarters, quay, and port, are considered as well.

In each of the cases, the height of the island is set at +8 m LAT. A sand pancake (~7m) will elevate the island structure towards some -23NAP, and from there on the design criteria for the island are taken from the Quick-scan Eiland op Zee, which include

- Construction depth is at -23 m LAT
- The height of the island is at +8 m LAT
- Design of the island for 1/250-year storm conditions
- Design water level at +4.9 m LAT
- Design wave height Hs = 8.45 m
- Overtopping 0.1 l/m/s

The distance from the coast also has an influence on logistics. This influence can have both a positive as a negative effect on price, depending on where the logistics is coming from. Currently, fuel consumption for logistics is estimated as being MGO (marine gasoil/DMA), however with the current energy transition going on in the marine industry and by the time these islands will be constructed it is very likely that these mineral fossil fuels will be replaced by:

- LNG (Liquified Natural Gas) or even green LNG. LNG has about 25% lower CO_2 emission compared to MGO.
- Biofuels, such as biofuel blends (30% bio part, 70% fossil part) up 100% biofuel.
- Green methane (CH_4)

Table 4.11: Material used for sandy island construction.

	With sheltered harbour and full functionalities	Without sheltered harbour and dedicated P2G functionalities
Sand (million m³)	23.82	17.81
QRN/Gravel (million ton)	7.35	7.37
Rock 40-200kg (million ton)	0.14	0.18
Rock 0.3-1.0T(million ton)	4.47	1.07
Rock 10-1000kg	0.06	
Rock 10-60kg	0.25	
Rock 3-6T (million ton)	1.68	1.47
Rock 10-15T (million ton)	0.30	0.24
X-Block 43.2T (units)	19602	13125
X-Block 43.2T concrete (million m³)	0.25	0.24
Caissons (22.5x22x55)	9	
Caisson's concrete (million m³)	0.03	
Ring road concrete (million m³)	0.03	0.03
Fuel (marine gasoil MGO) (million ltr)	175	133

4.4.2.1.2 Cost parameters

In Table 4.12 the unit prices of the different elements of the island that serve as a basis for the CAPEX calculations can be found. The bandwidth on these unit prices is -35%/+35%. This bandwidth takes the following into account: the influence of the East-West positioning, the corresponding wave climate, and uncertainties related to design, scheduling, and risk.

The budgets are based on the new quantities and are higher compared to NSE3 (45), due to:

1. Detailed quantity take off from 3D model from the actual location
2. Allowance for installation tolerances and losses
3. Recent supply costs of rock/concrete
4. Allowance for general management and auxiliary, evacuation and safety marine spread to deal with offshore working conditions 100km from shore

The inclusion of a fully equipped harbour with sheltered docking facilities significantly affects the design, material need and thus cost. The sheltered harbour design costs about €1.5 billion and is about 35% more expensive than an island without a harbour. The budget price for OPEX is also based on the findings in the Quick-scan Eiland in Zee (44). The budget for management and maintenance of the island is 3,000,000 €/year. The bandwidth on this budget price is - 25% to + 100%. Overarching management accumulates to some 228 M€ for the sheltered harbour design with full functionalities and some M€172 for an island without a harbour dedicated P2G functionalities. Caisson island structures are expected to be at least at similar or potentially lower cost ranges.

Table 4.12: [Top] Unit prices of the different element of the island. [Bottom] cost breakdown for two island configurations for comparison with platform option.

Description	Budget Unit Prices (-35% to +35%)
Revetment	300,000 to 320,000 €/m
Breakwater	320,000 €/m
Sand fill (incl. royalties and compaction)	7.5 €/m³
Cable landing facilities	45,000.000 €/TP
Harbour, quay walls incl. scour protection and bollards	125,000 €/m
Harbour, slope + jetty	25,000 €/m

Table 4.13: CAPEX breakdown of two artificial energy island designs

	Fully equipped island with harbour	'Like for like' island with platform option
Characteristics		
Capacity	4 GW	4 GW
Dimensions	700 x 880 m	500 x 480 m
Total footprint	615,951 m²	243,890 m²
Structure CAPEX elements		
Revetment costs	958 M€	608 M€
Breakwater costs	320 M€	320 M€
Sand fill (incl. Royalties and compaction)	179 M€	134 M€
Cable landing facilities	45 M€	45 M€
Harbour quay walls	46 M€	0 M€
Harbour slope + jetty	8 M€	0 M€
Total structure CAPEX	***1556 M€***	***1107 M€***

Zooming in on the costs of both island structures fully equipped with harbours and bald 'platform like' islands, Table 4.12 [bottom] describes the more detailed cost compositions that are seen.

4.5 Platform and island structure cost comparison

Comparing platform and island structures for P2G activities is subject to several caveats. Both types of structures have their own characteristics; such as platform structures are typically built with process equipment and then installed offshore. Platform structures are compact and optimised in the Subsequent expansion or repurposing of platform structure to other use functions is constrained to existing structure specifications (space available, weight limitations, etc). On the other hand, bare island structure is built offshore first, and then desired process equipment is installed. Subsequent expansion or repurposing of island structure to other use functions is easier.

In order to compare costs of platforms and island structure housing 4 GW electrolyser, cost of 500 MW platform with process equipment was scaled proportionally. To accommodate 500 MW P2G, the structure (incl. installation) costs 161 M€. Ergo, a 500 MW multi-platform cluster with a total 4 GW P2G structure (incl. installation) costs 1288 M€. In the case of island structure sized for 4 GW P2G, the cost of construction was estimated at 1120 M€. In this comparison, the island structure is cheaper, but it is crucial to note the total platform cost will likely decrease due to economic scaling for both structure fabrication as well as installation. If we consider the ‘0.6 rule’ for economic scaling, the cost of 4 GW multi-platform cluster cost according to scaling formula,

$$\frac{C1}{C2} = \frac{V1}{V2}^{0.6}$$

would be, C1 (cost of 4 GW multi-platform cluster) = 560 M€ (incl. installation). This cost reduction and other potential cost factors affecting economies of scale should be further investigated to determine suitable offshore P2G structure.

Irrespective of economies of scale for cost of platform, other system design aspects can lead to lower total system cost. For instance, as windfarm size increases, optimising array cables can also lead to cost and complexity reduction. For instance figure 4.19 shows two potential topology of inter-array cables for 8 platforms of 500 MW each alongside a 4 GW island assuming 15 MW turbines, rotor diameter of 236 meter, 7D distance between turbines in a square grid. Additional details can be found in Appendix. In this comparison, the 8 platform topology results in 440 km of inter-array cable, whereas the island topology results in 698 km of inter-array cable. The shorter length of inter-array cable will lead to lower cable cost, and consequently low total system cost of a 4 GW P2G installation consisting of 8 500 MW platforms. This highlights the importance of system-level cost optimisation in addition to individual component-level techno-economic cost optimisation.

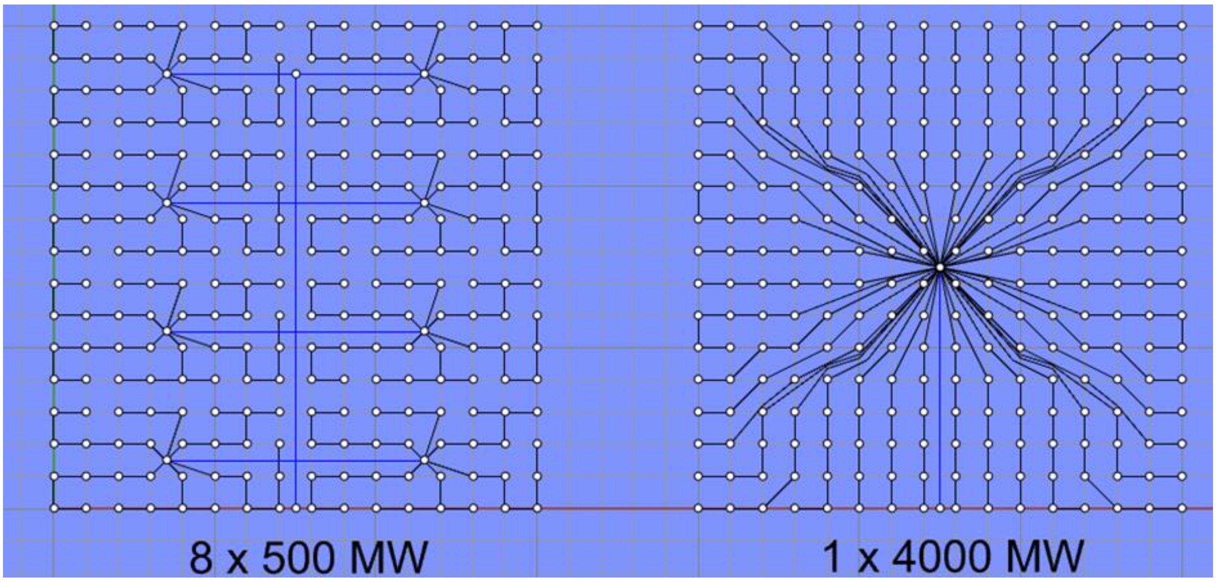

Figure 4.19 Topology of inter-array cabling connecting wind turbines (circles) to the P2G platform. Cable length for the left configuration is 440 km whereas for the right configuration is 698 km.

4.5.1 Process design costs

Tebodin has designed the process design for 500 MW offshore P2G along with a cost estimate. Additional details regarding the basis of design and costing can be found in Appendix C.4.2.5. The total costs for the process design was estimated at 635 M€ for the process equipment. The largest share of the costs (55%) was attributed to electrolyser PEM stacks. In order to determine this cost, a cost factor of 700 €/kW was assumed (46) (47) (48) (49). The remaining 285 M€ cost are for other equipment (e.g. desalination, power transformers, AHU & cooling), bulk materials & subcontracts (e.g. piping, electrical, instrumentation, control systems), project management and installation costs. The total cost of a 500 MW P2G platform, including process equipment and installation is 796 M€.

Independently, IV-one also performed cost estimation based on the total weight of platform structure and process equipment (incl. installation, excl. electrolyser PEM stacks). This cost estimation is based on the weight of the platform structure and equipment and considers that most equipment is already placed in the platform before the platform is installed offshore. This estimation resulted in 450 M€ for a 500 MW P2G platform. If the costs of electrolyser PEM stacks are added to this estimate with similar costs assumed for electrolyser stacks as in the estimation of Tebodin (700 €/kW, which represents 350 M€ of stack costs), the total cost of 500 MW P2G platform cost estimate is 800 M€.

Via both these independent methods, the cost of 500 MW P2G platform (incl. installation, process equipment and PEM stacks) is in the same order of magnitude. This reinforces the reliability of cost estimates used later in the report.

4.6 Market input data and financial parameters based on WP6

The work in this specific study has a strong relation with the energy system modelling work (WP6). The energy system model yields why and what we can expect to do offshore regarding hydrogen production and carbon storage capacities. This focusses mainly on where dispatch of certain activities, such as hydrogen dispatch can be expected. A first broad estimation (upper limit) of these capacities, based on II3050, is given in the table below. The II3050 national scenario foresees a large role of offshore wind in the energy mix, initially estimated to be 52 GW, though manually updated with the 38 GW and 72 GW development scenarios as stated in the recent Kamerbrief. The load factor is also manually altered to 4000-6000 hours per annum.

Table 4.14: Capacity estimations

		Adjusted to dedicated hydrogen		
	Unit	II3050	Low (38 GW)	High (72 GW)
CO_2 supplied	Mton/a	3.5	3.5	3.5
Electricity demand (domestic)	EJ/a	0.9	0.9	0.9
Electricity supply offshore wind	EJ/a	1.1	0.8	1.4
Capacity wind offshore	GW	52	38	72
Capacity of electrolyser	GW	32.5	23	40
Electric input for electrolyser	EJ/a	0.6	0.4	0.7
Hydrogen output from electrolyser	EJ/a	0.4	0.3	0.5
Running hours[20]	Hours	4800	4800	4800

The capacity/volumes of CO_2 demanded and/or supplied per region (Rotterdam, Amsterdam, den Helder and UK) are set to meet - or at least not interfere - with the existing plans and ambition, which was identified by representatives of the respective regions and discussed in the storylines.

4.7 Modelling approach

The system value configuration of the commodity flows and the type and levels of investment associated with these flows will vary between the energy hubs (i.e., from an overall energy system cost perspective). The objective of the model is to give an indication on how system integration could look like in a specific geographical area, what relationships exist between the various stakeholders (investors), and what the cost and potential benefits are for combining energy-use functions on a system level. The model will not provide an optimum configuration of system integration in the selected geographical region, nor will it provide a quantitative analysis for the business case of the individual asset owners.

For each storyline, the model will retrieve the net present cost for system integration within the energy hub, while analysing various transmission corridors connecting these energy hubs to the shore. The Net Present Cost (NPC) & Net Present Value (NPV)can be used to compare the various storylines, but also allow us to compare the potential for system integration between the regions.

The NPC/NPV methodology is a capital budgeting methodology that considers the time value of money. It can be used to evaluate investments or compare different investment alternatives. A capital investment usually starts with a negative cashflow, i.e., the initial investment, followed by a series of negative and positive cashflows over time. One must decide on the time period that should be considered for these cash flows, commonly referred to as the horizon of the business case. Using a discount rate, the future cashflows (which are adapted for inflation) are discounted to the value at the present date. Mathematically speaking, the NPC/NPR can be expressed as the sum of a series of discounted cashflows/revenues over the business case horizon $t = 1, \dots, T$:

[20] Should be altered to 55 to 57%, dependable on region specific wind speeds

Equation 2: General Net Present Cost and Revenue

$$\mathrm{NPC} = \sum_{t=1}^{T} \frac{\mathrm{Cashflow}(t)(1+inf)^t}{(1+r)^t}, \text{ and } \mathrm{NPR} = \sum_{t=1}^{T} \frac{\mathrm{Revenues}(t)(1+inf)^t}{(1+r)^t}$$

Where "Cashflow (t)" denotes the cashflow at time t (set to 2020-2070) expressed in money of today, inf denotes inflation set at 2%, and r denotes the discount rate applied (set at 10%). Many companies calculate their weighted average cost of capital (WACC) and use it as their discount rate when budgeting for a new project. In this analysis, the salvage value of an asset at the end of its life has not been considered as a positive cashflow.

The unit technical cost (UTC) is the profitability indicator used in the oil and gas industry to determine the cost of producing a barrel of oil. Other sectors, like the offshore wind sector, use the Levelized Cost of Energy (LCOE) terminology. The UTC/LCOE is used particularly in situations where a comparison of different technologies or investments with varying lifetimes needs to be undertaken. The UTC/LCOE is defined in this report as:

Equation 3: General Unit Technical Costs

$$\mathrm{UTC/LCOE} = \frac{NPC}{\sum_{t=1}^{T} \frac{\mathrm{Volume}(t)(1+inf)^t}{(1+r)^t}}$$

A long-term outlook is adopted (up to 2070). Hence there is a need to: (I) set a proper time horizon for the various investments; (II) forecast future costs (looking forward); and (III) adopt appropriate inflation and discount rates to calculate the present value of future costs and benefits. Financing trends such as reduced risks, decreased debt, interest rates, and reduced required return on equity can generally be identified to have an impact on the costs for system integration. Decreasing risk premium for debt financing and the required rate of return, for the wind sector as for TenneT, has had a substantial effect on cost reduction (nearly 14%) for offshore wind (54).

Previous NSE studies undertook calculations by a common weighted average cost of capital (WACC) for all system integration activities under consideration. The cost of capital is the rate that a company/consortium is expected to pay on average to all its security holders to finance its activities. The firm's cost of capital is commonly referred to as the WACC Importantly, it is dictated by the external market and not by management. Applying a single sector or even firm-specific costs of capital to a pool of activities can lead to an over- or under-estimation of the financial risks perceived by the market. However, little is known about how financial investors are valorising the risk profile, and the cost of capital for system integration projects comprising of multiple assets and stakeholders.

In order to determine the WACC(s) that reflected the perceived risk profile of projects due to offshore system integration, interviews were held with industry and sector specialists. Interviewees like government/policy influencers, value chain operators, and financial institutions graded their perception of risks (low/medium/high) for various risk categories in the power-to gas value chain like market risks, policy/regulatory risks, technology risks and value chain risks. The qualitative information from the interviews was quantified into WACC values which were then applied in the techno-economic model to determine the NPC and NPR of different hub storylines. Other insights generated in the interviews regarding the risk perception of the power-to-gas value chains by industry and specialists are provided in Appendix B.8.

5 Results

In this chapter the results of the techno-economic analysis of the development of the system integration activities in the various hubs are discussed. The interlinkage between the three hubs will be discussed at last.

5.1 Hub West

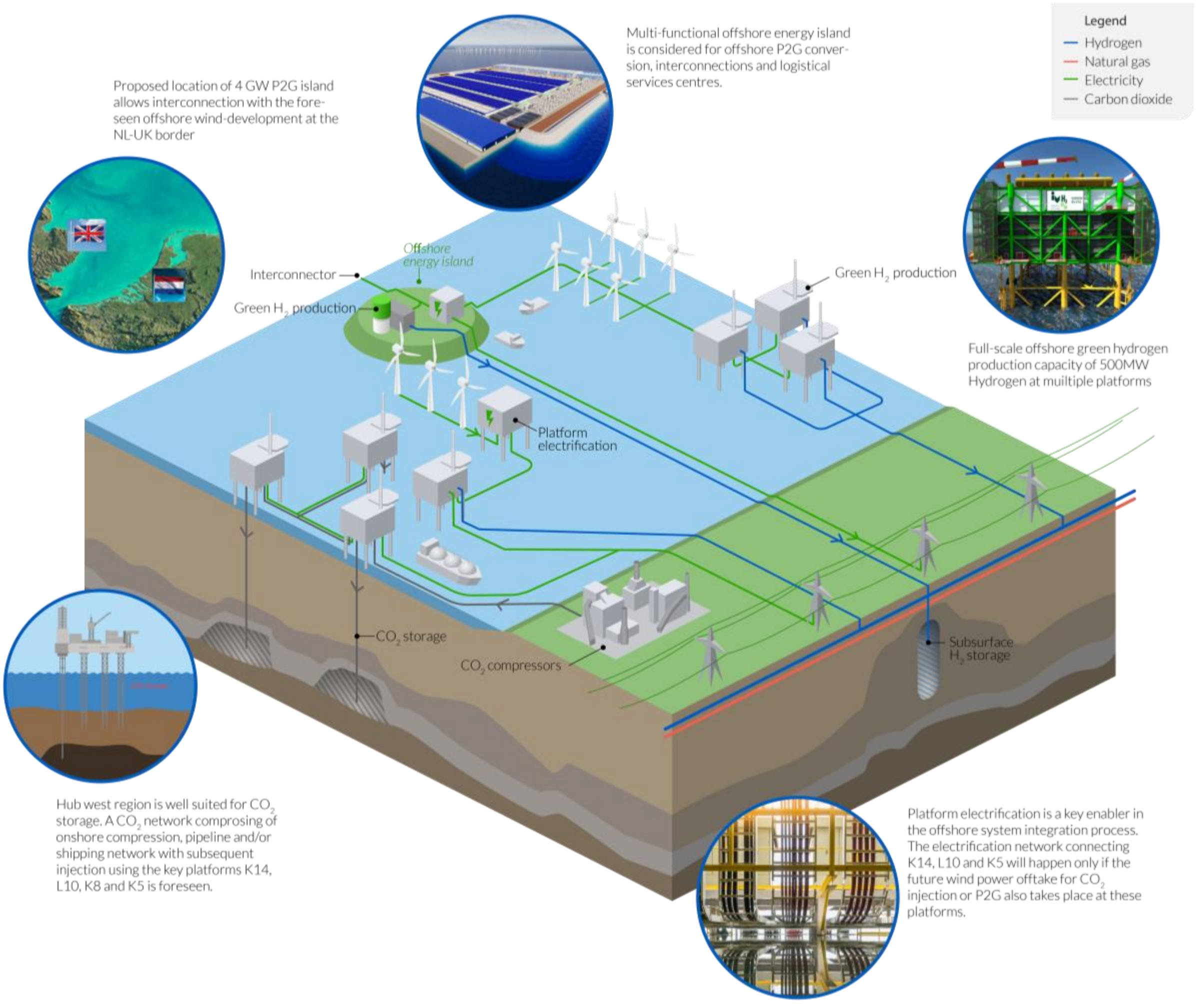

Figure 5.1 Schematic showing key elements of Hub West.

The storylines – summarised in chapter two - contain a set of common activities and characteristics (See Figure 5.1 for a schematic of Hub West). These activities are the development of a CCS network as well as the set-up of an electrification network. Variations related to the configuration of the P2G facility and the transport network. The storylines cannot be one-to-one compared to each other as configurations of offshore system integration activities have different investment and operational time-windows. Table 5.1 summarises the KPIs for the various scenario results of Hub West and Figure 5.2 shows the NPC for the three Hub West storylines. In the following section these parameters will be discussed in further detail and compared to industrial insights. In order to provide an indicative NPR, the electricity, hydrogen and methane prices generated by WP6 are used, resulting from the II3050 national scenarios. For platform electrification no revenues are assumed.

Table 5.1: KPIs Hub West

KPI	Storyline 1	Storyline 2	Storyline 3
Maximum annual (and cumulative) vol. offshore CO_2 network	26.5 Mton/a (602 Mton)		
NPC offshore CO_2 network	0.5 B€		
UTC offshore CO_2 network	3.3 €/ton	2.9 €/ton	2.8 €/ton
Maximum annual (and cumulative) vol. offshore wind produced	34.0 TWh/a (1055 TWh)	43.4 TWh/a (1346 TWh)	
Maximum annual (and cumulative) vol. electricity landed onshore	10.2 TWh/a (315 TWh)	19.3 TWh/a (598 TWh)	
NPC offshore wind production	7.5 B€	11.3 B€	
NPR offshore wind production	12.4B€	18.1 B€	
UTC offshore wind production	40.9 €/MWh	42.0 €/MWh	
UTC offshore transmission	15.3 €/MWh	13.1 €/MWh	
Maximum annual (and cumulative) vol. consumed for electrification	N/A	0.44 TWh/a (1.9 TWh)	0.68 TWh/a (2.8 TWh)
NPC electrification	N/A	272 M€	332 M€
NPR electrification	N/A	0 M€	0 M€
UTC electrification	N/A	140.5 €/MWh	306.6 €/MWh
Maximum annual (and cumulative) vol. H_2 produced	0.48 Mton/a (15.0 Mton)		0.54 Mton (16.6 Mton)
NPC H_2 production	4.4 B€	4.9 B€	6.3 B€
NPR H_2 production	6.7 B€	6.4.B€	7.3 B€
UTC H_2 production (excl. electricity costs)	1.7 €/kg	1.9 €/kg	2.1 €/kg
UTC H_2 transport	0.6 €/kg		

Storylines 1: P2G on a sandy island

In this storyline, a dedicated P2G infrastructure in Hub West is located on an artificial island in the proximity of the K8 area (wind area 1). The produced hydrogen is transported to shore by a new, dedicated hydrogen pipeline. The expected P2G capacity, via direct coupling with an offshore wind park, is 4 GW. The NPC of this system is approximately 15 B€ (See Figure 5.2). The development of offshore wind (~50%), a joint CO2 transport, storage, and injection network (~ 4%) as well as the development of offshore hydrogen production and transport network (~ 39%) have the highest contribution.

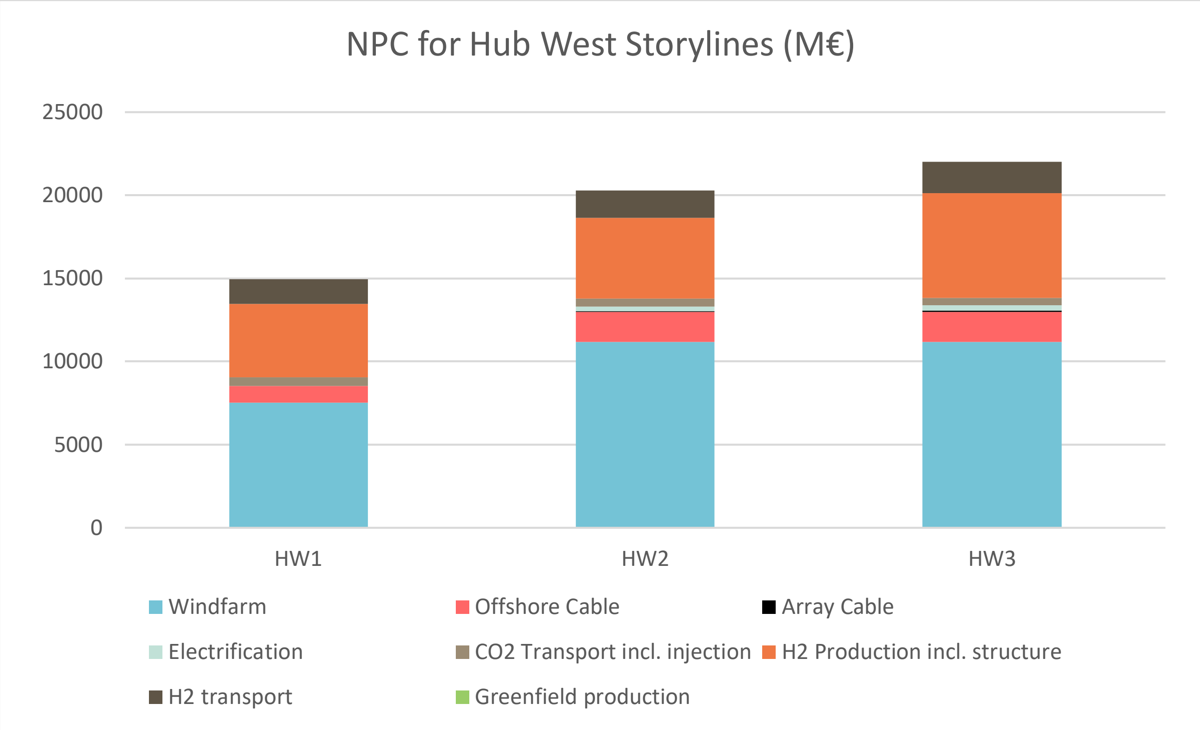

Figure 5.2 NPC for the three hub West storylines

Storyline 2: Dedicated P2G on multiple platforms

Figure 5.2 shows that the NPC-values for storyline 2 are approximately 20 B€. In this storyline, dedicated P2G in Hub West is clustered around platform K8 on a set of multiple new platforms - This means that some 8 new platforms are placed around K8, with a total contribution in costs of about 4.9 B€.

Electrification of K5 takes place via K14, which, once a short connection to K8 is realised, ensures a small baseload grid connection of the P2G installations. The relative costs of platform electrification are low. The joint CO2 transport, storage, and injection network costs about 473 M€, close to the 543 M€ estimated for storyline 1. Although, the capital expenditures of the multiplatform P2G configuration are just slightly lower than those for the dedicated P2G island, the time value of money – has a higher positive impact on the NPC of a multiplatform configuration. This effect can be explained by the relatively long investment period considered for island configuration (seven years) in comparison to just two years of investment for the multiplatform configuration. The early electrification (2026) of the K14 and K5 region is reflected in the higher costs share related to the development of the IJmuiden-Ver (extra) wind region. These NPC of developing this wind area in combination with realisation of an electrification network was not considered under Storyline 1.

Storyline 3: Dedicated P2G on multiple platforms and flexible P2G at single platforms

In addition to the dedicated P2G production described in storyline two, flexible P2G at L10, K14 and K15 is applied, increasing the total NPC of system integration in Hub West by about 1.5 B€ to a total of approximately 22 B€. L10 serves as a collection hub for hydrogen produced at the other key platforms. The scenario includes electrification of all key platforms through Hollandse Kust West and/or via indicated wind areas 2 and 8. Figure 5.2 describes the NPC associated with these additional functionalities. The NPC electrification costs are slightly higher – approx. 73 M€) than the cost described in the previous scenario. These additional costs are for a great extent related to additional P2G capacity and the extension of the electric network to L10.

In the following section the individual integration options are discussed in further detail and compared to industrial insights.

5.1.1 Development of a CO_2 network

Figure 5.3 summarises the capital costs associated with carbon storage in the Hub West region under storyline three. The total costs for CO2 transport and storage activities to Hub West are the lowest in this scenario. This can be explained by the fact that part of the electricity network can be used/re-used for ccs activities and thus no additional power provision to K14, K5 and L10 has to be realised. In the other Hub West scenarios, an off-grid power solution is considered to provide the power demanded for CCS-activities.

Total CAPEX accumulates to some 1100M€ in the base case – some 26 Mton/a of CO_2 is stored - and comprises of onshore compression, offshore transport, and offshore injection. CO_2 transport by ship is perceived as an economic option if volumes are at least 0.5 Mton/a and below 5Mton/a. Cost of transporting CO2 by shipping is reported to be 50 €/ton by Carbon Collectors[21].

The alternative case concerns lower CO_2 volumes available in the Den Helder and Amsterdam port region. This is in line – for instance – with the latest announcement to cancel the Athos project. The lower volumes of CO_2 coming available via these port regions can be collected by dedicated CO_2 shipping vessels. The shipping distance will be within the 400 km range. The CAPEX of this alternative approach – in which some max 17.8 Mton/a of CO_2 is stored - is some 1400 M€.

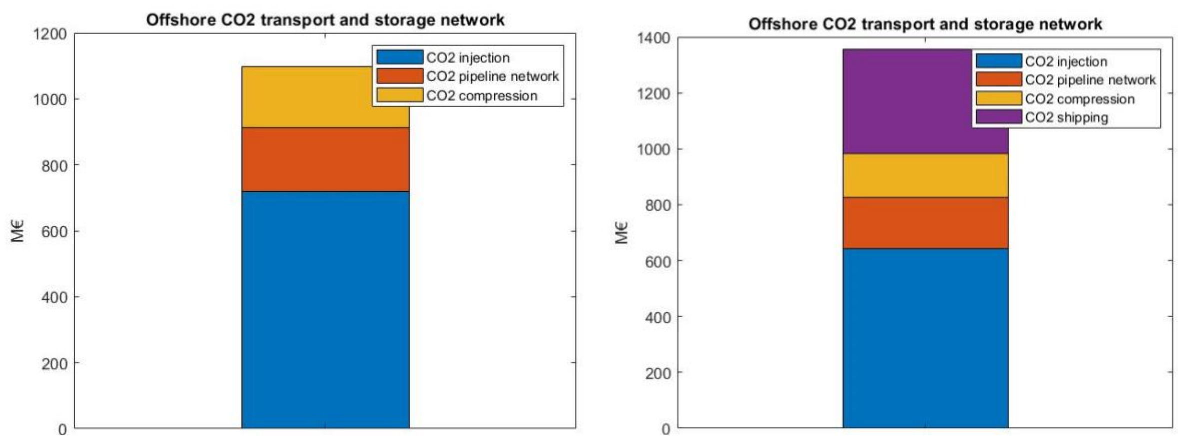

Figure 5.3: Offshore CO2 transport and storage costs related to Hub West. To the left: offshore pipeline network with injection capacities of 14Mt from Rotterdam, 6Mt from Amsterdam and 6Mton from Den Helder. To the right: a combined network with pipeline injection capacity of 14Mt from Rotterdam and 3.8Mton from shipping.

The total investment and operational costs of the baseline scenarios are in line with estimates of Wildenborg et al. (55). Their cost estimate – some 970 M€ - comprises also the investment and operational cost of CO_2 injection in the P-fields, which were not included in the Hub West analysis. The UTC of both cases – 3.3 €/ton (base) and 3.4 €/ton (alternative) are also slightly lowerthan estimated provided by Gasunie and EBN (18 p. 57) for the K14/K15 and L10 field.

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[21] Carbon Collectors: Commercially ready technology to collect, transport and store CO_2 in empty offshore gas fields.

The EU ETS price for carbon has increased the past year from some 35 €/ton (March 2021) to some 80 €/ton (March 2022). The strong increase makes future revenue prediction uncertain from carbon storage services.

5.1.2 Cable connecting the gas platform with the substation

Partner Boskalis has provided estimates for the electricity cables (all 66 kV) to support an integrated power network for the electrification activities in the K/L blocks (30) (see Figure 5.4). The bold connections highlight power lines that fall into the system boundaries for Hub West, though, in the default case the capacity of these lines is set such that platforms located outside the Hub West boundary can still be electrified. Although the cost of extending the power network outside Hub West is not considered, the larger capacity can support the later phase for P2G activities near the selected platforms.

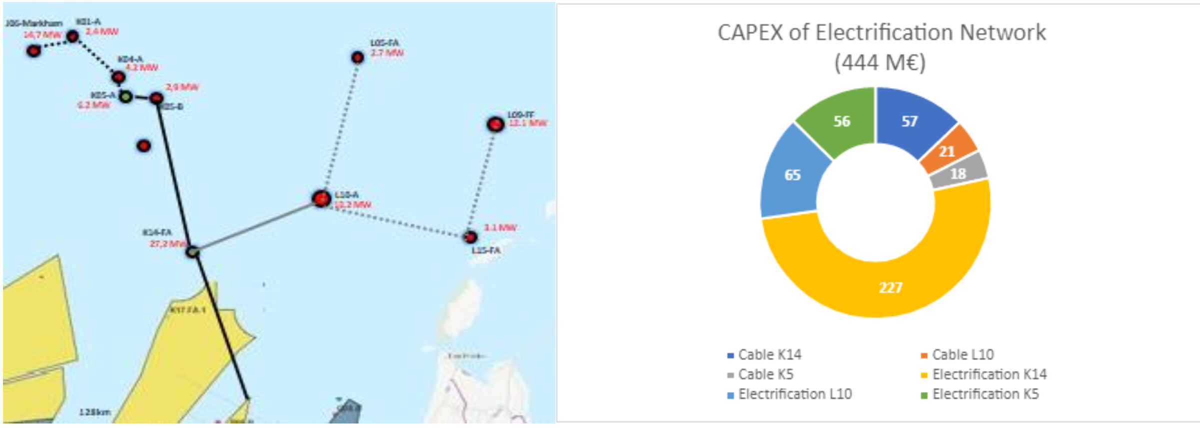

Figure 5.4: Integrated power network for electrification activities in the K/L blocks. On the left: the electric network via Hollandse Kust West. Although, further away, the wind location is earlier available. On the right: the CAPEX associated with this electrification network, where investments at platform K14, L10 and K5 are considered.

The CAPEX associated with this integrated power network is some 444 M€ and comprises of the cabling costs of the network, the replacement of the current installed gas turbines and the integration of auxiliary power requirements in power distribution on new dedicated platforms. The delta benefits of electrification – for instance - higher efficiency, lower operational costs, and higher volumes of gas available for the market are considered in the NPV as well.

5.1.3 P2G production and structure costs

Figure 5.5 shows the CAPEX costs related to dedicated offshore P2G activities on a sandy island structure (left) and on multiplatform structures (right). Structural costs for a multiplatform dedicated P2G configuration are currently slightly higher (1288 M€) than structure costs related to a sandy dedicated P2G island (1120 M€). Though, the figure below compasses a conservative approach with regard to the number of platforms required to host the combined 4 GW capacity. The figure below considered 8 new platform structures, whereas expert judgement indicates that combining and integrating various functions (living quarters, control rooms etc.) could reduce the number of platforms required to 6 or even 5 (805-966 M€). Such a reduction would reduce the structure costs of the offshore platform configuration by about a third. In some cases, existing platform facilities could be re-used to facilitate part of the P2G functionalities (e.g., injection platforms) which would reduce the structural costs of multiplatform configurations further.

Another consideration is the main cost factors that impact the structure costs of both platforms and islands. The platform structure costs are significantly impacted by the steel price. The island structure costs are subject to the fuel price, as loads of fuel is used by construction vessels to move the sand and other resources to the island. Both, steel and fuel, costs are significantly changed since February 2022. In this study costs and prices before this period are used.

The figures below do however not consider the technical and economic lifetime of the structure. Sandy island structures have an expected lifetime duration of 100 years, which is at least twice (and potentially more) as long at the technical lifetime of multi-platform configuration. Hence, re-installation of platform structures should be foreseen as well.

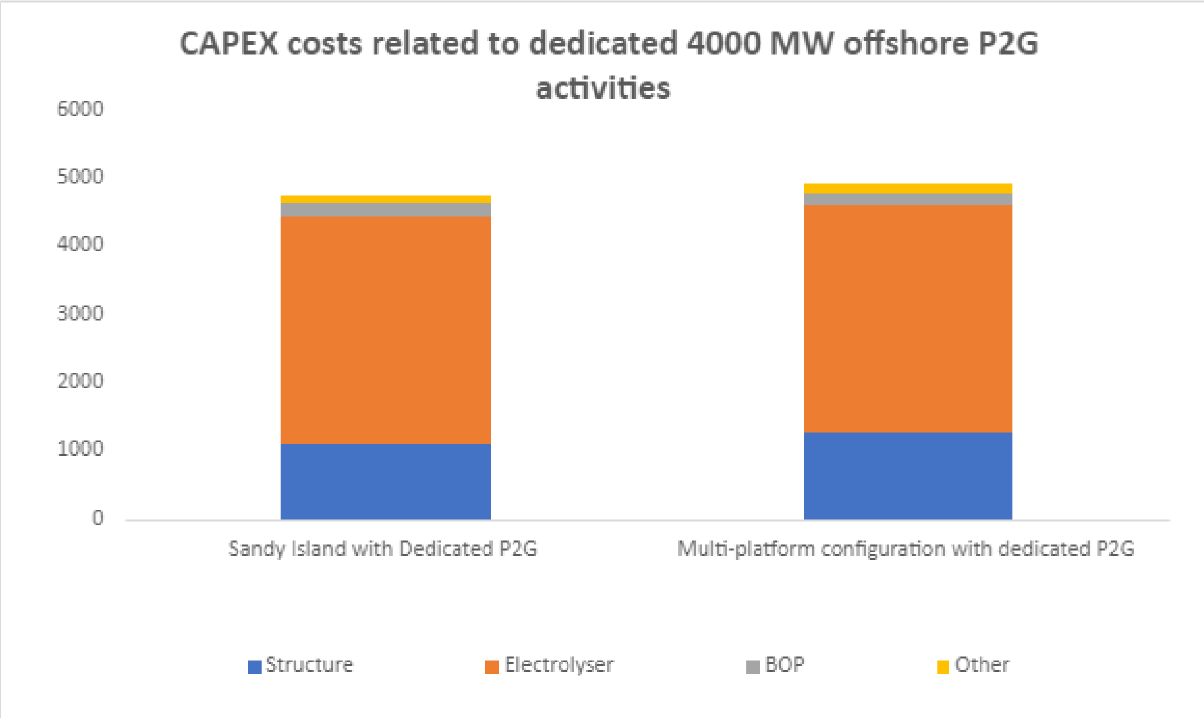

Figure 5.5: CAPEX costs related to dedicated 4000 MW offshore P2G activities comparing a sandy island structure without a harbour with a multi-platform configuration with a minimum of 8 platforms.

5.1.4 International integration

5.1.4.1 Potential for interconnections with the UK

The Southern North Sea (SNS) benefits from this diverse set of energy infrastructure that can be relevant in the energy transition and net zero ambitions. It also offers the opportunity to integrate with other regions such as the Hub West region on the Dutch continental shelf. International integration of Hub West with the UK has been analysed with respect to CO2, electricity, and hydrogen exchange. The review of literature on CCUS potential in the SNS along with the projects highlighted in the Appendix that there is huge potential for CO_2 capture and storage either in depleted oil and gas fields or within saline aquifers in the North Sea. UK's electricity demand is projected to be in the range of 300-375TWh/yr. by 2030 and 450-700 TWh/yr. by 2050. In addition, the UK's hydrogen demand is projected to be in the range of 5-30TWh/yr. by 2030 and 110-590 TWh/yr. by 2050

There is an estimated 78Gt CCS storage potential in the CNS and 10-20Gt in the SNS. This could provide the opportunity for the Netherlands to store CO2 in UK Reservoirs. New routings to these sites from the in the Netherlands proposed CO2 network would then need to be considered.

On the UK side some major trunklines will be offline in the next few years which could be repurposed and offer opportunity for the Netherlands to be integrated with energy hubs in the UK such as Theddlethorpe and Bacton. The re-use of these pipelines is viable however integrity checks would be required.

The Sean P to Bacton Terminal Trunkline would provide the closest link into Hub West and it is viable that this pipeline could be repurposed subject to integrity checks. An interconnector would still be required which would involve an extensive offshore campaign. This pipeline is still in use and discussion as to its future potential would be required to be held with the operator ONE-Dyas (see also the figure below).

For new connections to the UK, it was proposed that following a similar route to the BBL line may be more suitable at it: avoids lots of infrastructure with the SNS being quite congested and runs between wind leasing areas providing potential connections into these areas. This should be analysed in further detail.

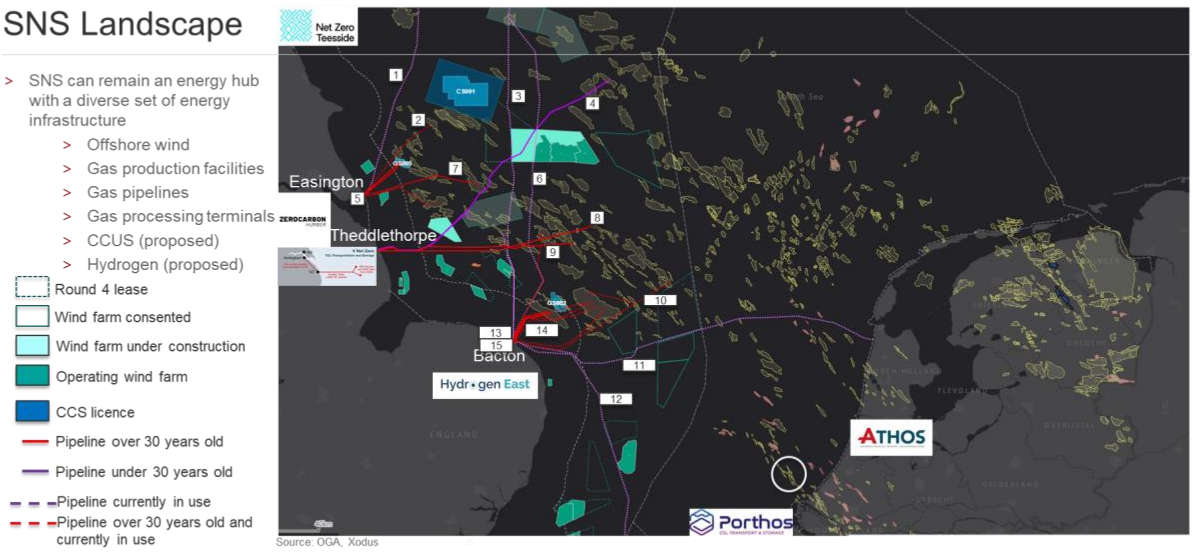

Figure 5.6: SNS Landscape (Source: XODUS, OGA)

5.1.4.2 Potential CO2 interconnection with Norway

Another potential interconnection of Hub West relates to the enormous CO2 storage potential in the Norwegian empty hydrocarbon resevoirs. The first relevant CCS project in the Norwegian part of the North Sea is the Northern Lights project, which is planned to become operational in 2024. In the first phase it aims for storing 1.5 Mtpa of CO2 and a potential expansion towards 5 Mtpa of CO2. The second relevant CCS project in the Norwegian part of the North Sea is the Smeaheia project, which is aimed to become operational in 2027. In the first phase the early estimate is to aim for 5-10 Mtpa of CO2 and a potential expansion towards 20 Mtpa of CO2. A last relevant CCS project in the Norwegian part of the North Sea is the ArchiteCCS project, involving multiple storage sites connected to each other. This project will not become operational before 2027. In a first phase 5 Mtpa of CO2 storage is foreseen with a huge scale up potential up to above 50 Mtpa. Next to these projects located in the North Sea, Norway has potential for CO2 storage in the Barents Sea further up to the North as well.

Muliple types of connections, such as medium and low pressure CO2 ship transport, or re-used and new pipelines, can be foreseen to these Norwegian storage fields, based on the transport volumes, distances, required flexibility and availability of existing pipelines. A relevant interconnection opportunity of Hub West is to connect the proposed CO2 network with the Draupner-Duinkerke pipeline that runs from Belgium and France to Norway. This pipeline is crossing Hub West. The figure below illustrates the potential for an international offshore CO2 network to store CO2 from European countries. Obviously, the need and economic viability of such a massive CO2 pipeline network depends on the intensity in which CCS is part of the decarbonisation strategy in the European countries.

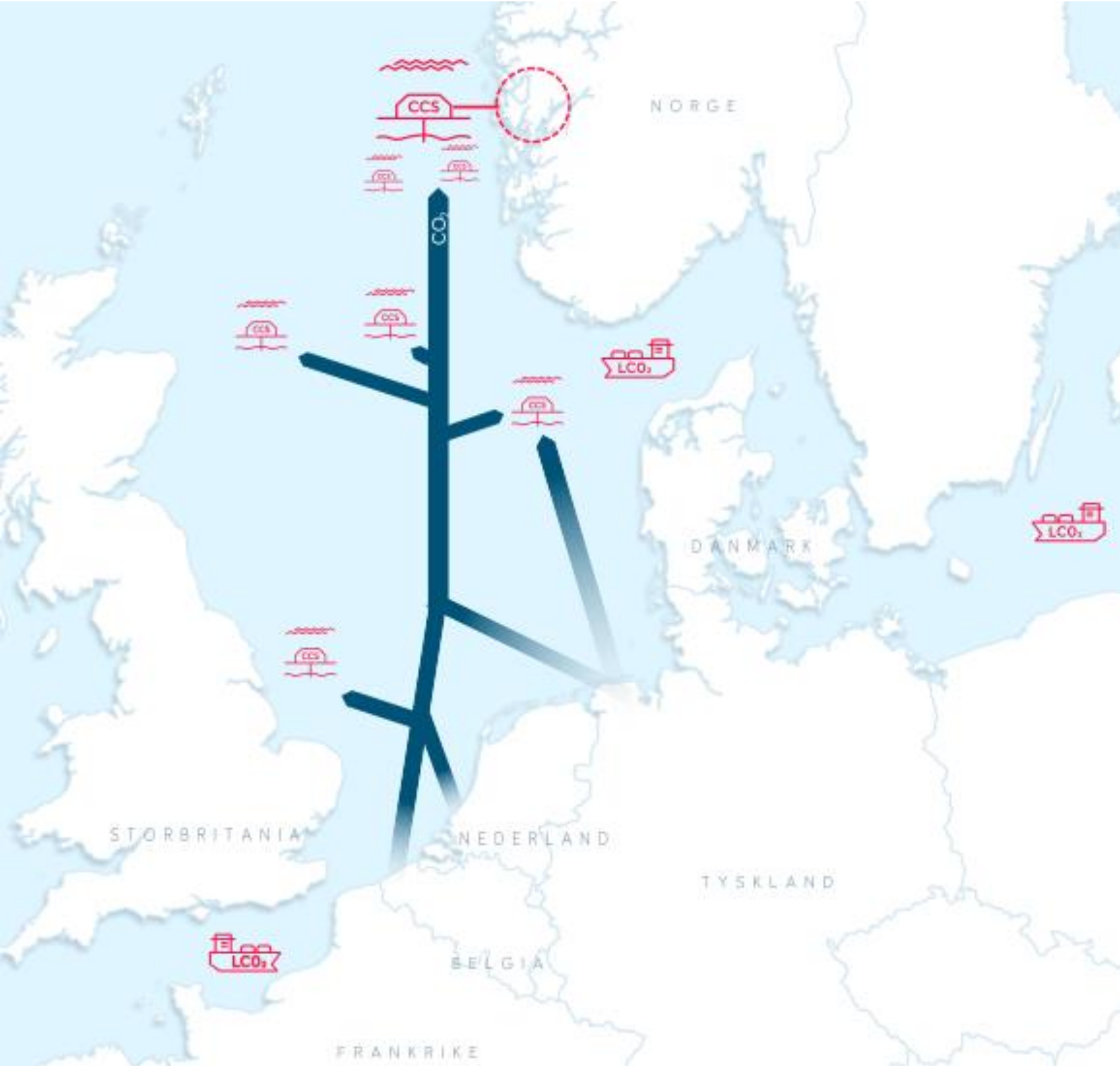

Figure 5.7: Vision of potential CO2 export towards the Norwegian hydrocarbon fields (52)

5.2 Hub East

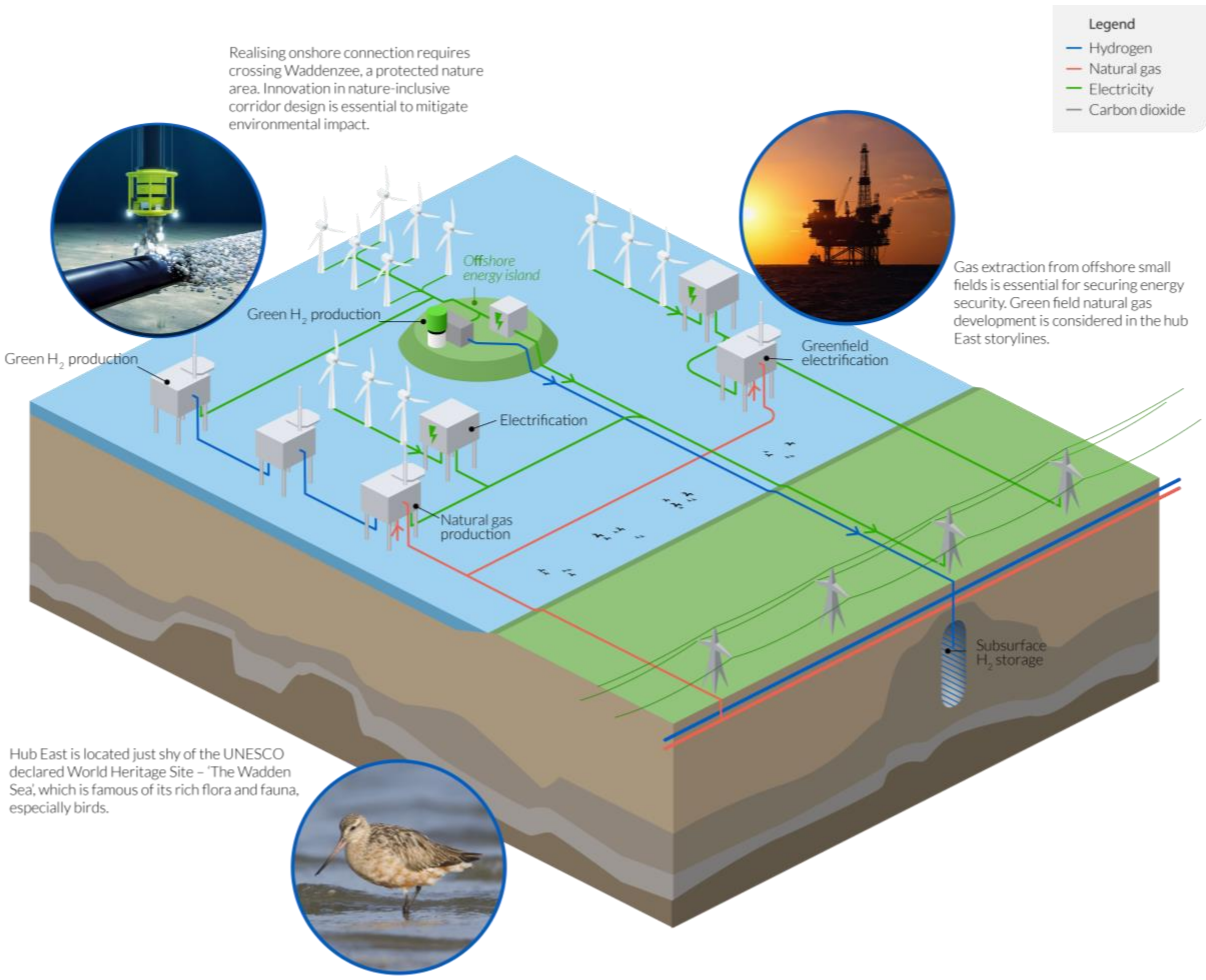

Figure 5.8 Schematic showing key elements of Hub East.

The storylines – summarised in chapter two - contain a set of common activities and characteristics (See Figure 5.8 for a schematic of Hub East). These activities are the development of green field gas extraction as well as the set-up of platform electrification. Variations are related to the configuration of the P2G facility and the transport network. Table 5.2 summarises the KPIs for the various scenario results of Hub East and Figure 5.9 shows the NPC of the Hub East storylines. In order to provide an indicative NPR, the electricity, hydrogen and methane prices generated by WP6 are used, resulting from the II3050 national scenarios. For platform electrification no revenues are assumed.

Table 5.2: KPIs Hub East

KPI	Storyline 1	Storyline 2	Storyline 3
Maximum annual (and cumulative) vol. CH4 produced (GF)	2.0 bcm/a (13.7 bcm)		
NPC CH4 production	0.82 B€		
NPR CH4 production	0.77 B€		
UTC CH4 production	0.09 €/Nm³		
Maximum annual (and cumulative) vol. offshore wind produced	29.1 TWh/a (866 TWh)	39.2 TWh/a (1179 TWh)	29.1 TWh/a (866 TWh)
Maximum annual (and cumulative) vol. electricity landed onshore	0.3 TWh/a (8 TWh)	10.1 TWh/a (312 TWh)	0.3 TWh/a (8 TWh)
NPC offshore wind produced	7.7 B€	10.3 B€	7.7 B€
NPR offshore wind produced	13.2 B€	17.4 B€	13.2 B€
UTC offshore wind produced	39.1 €/MWh	42.6 €/MWh	39.1 €/MWh
UTC transmission	95.4 €/MWh	18.6 €/MWh	95.4 €/MWh
Maximum annual (and cumulative) vol. consumed for electrification	0.35 TWh/a (5.3 TWh)		
NPC electrification	47.3 M€		
NPR electrification	0 M€		
UTC electrification	23.1 €/MWh		
Maximum annual (and cumulative) vol. H2 produced	0.53 Mton (16.5 Mton)	0.28 Mton (8.7 Mton)	0.53 Bton (16.5 Bton)
NPC H2 production	1.9 B€	6 B€	6.6 B€
NPR H2 production	8.3 B€	3.5 B€	6.8 B€
UTC H2 production (excl. electricity costs)	0.45 €/kg	3.20 €/kg	1.90 €/kg
UTC H2 transport	0.53 €/kg	0.67 €/kg	0.65 €/kg

Storylines 1: Dedicated P2G on a sandy island
In this storyline, dedicated P2G in Hub East is located on an artificial island structure. The produced hydrogen is transported to shore by a new, dedicated hydrogen pipeline. The expected P2G capacity is set to 4GW. The NPC of the total system is about 13B€.
The development of offshore wind (some 60%), offshore cabling (some 20%) as well as the development of offshore hydrogen production and transport network (some 20%) have the highest contribution.

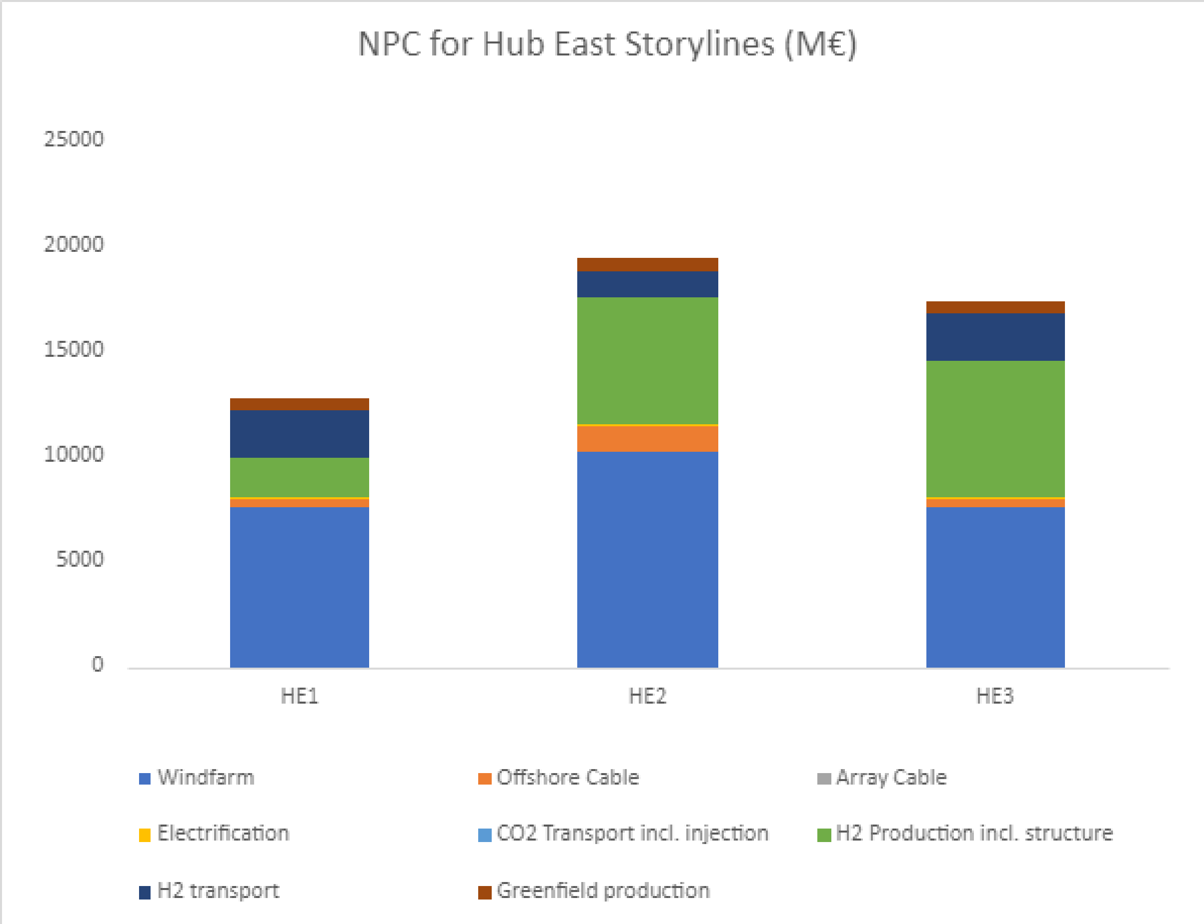

Figure 5.9 NPC for the three hub East storylines

Storyline 2: Flexible P2G on a sandy island

In this storyline, the function of the artificial island changes compared to storyline 1. For this storyline, the island provides electricity and hydrogen transmission in a fixed ratio (50:50) to provide a more flexible P2G set-up. Expected wind capacity is similar to storyline 1, though, the dispatch profile for the electrolyser follows market conditions now. The additional costs for installing a 2 GW HVDC cable from area 5 to Eemshaven is about 1.8B€.

Storyline 3: P2G on multiple platforms

Dedicated P2G in Hub East is clustered around G17 on a set of multiple new platforms. The total expected P2G capacity is again 4 GW. This means that depending on final sizing, eight new platforms are placed around G17 for P2G production. Optimal ways of transport of hydrogen from G17 to shore are studied. This could go through a blending scenario for NGT transitioning from a gas pipeline either to a hydrogen pipeline or to the development of a dedicated hydrogen pipeline.

In the following section these parameters will be discussed in further detail and compared to – where possible – with industrial insights.

5.2.1 Greenfield natural gas production

Electrification in Hub East does not take place via an integrated power network but via direct 33kV connections to the substation. The N5 platform is connected to the Riffgat substation located on the German continental shelf, whereas G17 is assumed to be connected to the existing 600 MW Gemini wind park.

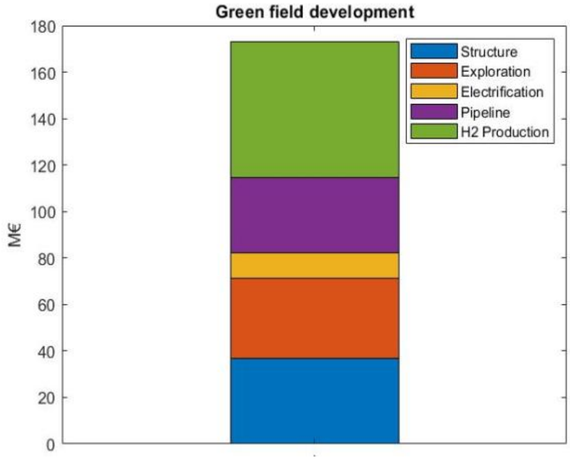

Figure 5.10: CAPEX greenfield development combined with offshore H2 production

In case of N5, the electricity cable is a 33kV cable with 20 MW capacity (addition 20-40 MW could be considered) (12). The cable has a total length of approximately 8.7 kilometres. The cable is buried at least one meter deep and laid with a jetting method. Regarding cable cost estimations similar methodology and cost function developed in previous NSE programmes are applied. The N05-A platform is designed as a gas treatment platform, which will then be connected to the NGT pipeline with a newly constructed pipeline. The new, 20-inch, pipeline will have a length of approximately 13 kilometres. There are some considerations by NGT to reduce the operational pressure, however, for this analysis the pressure is set between 85 and 90 bar (17). The offshore platform is integrated with a 20 MW P2G installation that will follow and act upon German electricity market conditions. This implies that the capacity the 33kV cable is extended with some 20 MW. Figure 5.10 shows the CAPEX required for the complete system. The LCOE/UTC of greenfield gas extraction is with 0.07 €/Nm³ below the unit costs (some 0.14€/Nm³) provided by EBN.

A proposal to increase the marginal field tax incentive to promote new investment was announced in 2018, but was not presented to the parliament until June 2020 because of disagreement within the government and protest by climate activities over fossil use and development (57). The increase in the marginal field incentive from 35% to 40% was finally passed in January 2021.

5.2.2 Cable connecting the gas platform with the substation

In case of G17, earlier insight in light of the TKI study 'on the economics of offshore energy conversion: smart combinations' (58) showed that the electrification capacity at the G-block would be 4-8 MW and that in actual practice, one could prefer to keep the gas turbines installed, insofar they are exempted from emissions requirements up to 500 hours per year, as it could be attractive to keep them as a back-up solution in times that the wind is not blowing. However, full replacement of current compressor trains by integrated compressor systems allows for seal-less compression of CO_2 or hydrogen for future business scenarios. This would be of interest for the G17 platform, given that the storylines consider G17 as a compression hub for future offshore hydrogen developments. Under this recognition, a 20 MW cable is expected to suffice current and future electricity demand for compression.[22] The investments involved are in the order of 47M€. This includes capex for refurbishment of the platform, the installation of an integrated 'future ready' compressor, the cable supply and installation (33kV) from the Gemini wind park over 35km.

[22] With an inlet pressure or 35 bar, a max. velocity of 25kg/s, the compression duty of a 4000 MW-4500 MW area is about 14.85-16.7 MW (model NSE 2 used for quick calculus and inputs used below).

5.2.3 P2G wind following vs. market following

The load factor for market following hydrogen production is some 20% below the load factor of dedicated hydrogen production. This process can be optimised by coupling additional markets (in this case) Germany or by offering additional services (e.g., frequency control). The advantage of market following hydrogen production is that the energy flows to the systems that offers the highest value per hour.

The market prices related to the outcome shown below are retrieved from WP6. Analysing the operational profile of the electrolyser it was seen that there are only few instances (mostly in summer) when the electrolyser system retrieves additional power from shore to run its process. This also implied that the benefits from selling electricity to shore are higher than using the electricity for conversion to hydrogen and instead selling the hydrogen to shore.

This effect explains the relatively higher UTC cost for offshore hydrogen production related to scenario 2, in comparison to scenario 1 and 3. One could also argue that the electrolyser capacity chosen in this instance is too big, and that smaller electrolyser system (about halve) could suffice. The cable capacity in this scenario is set to 2 GW, so that the electrolyser system will be put to use once the cable capacity is fully utilized.

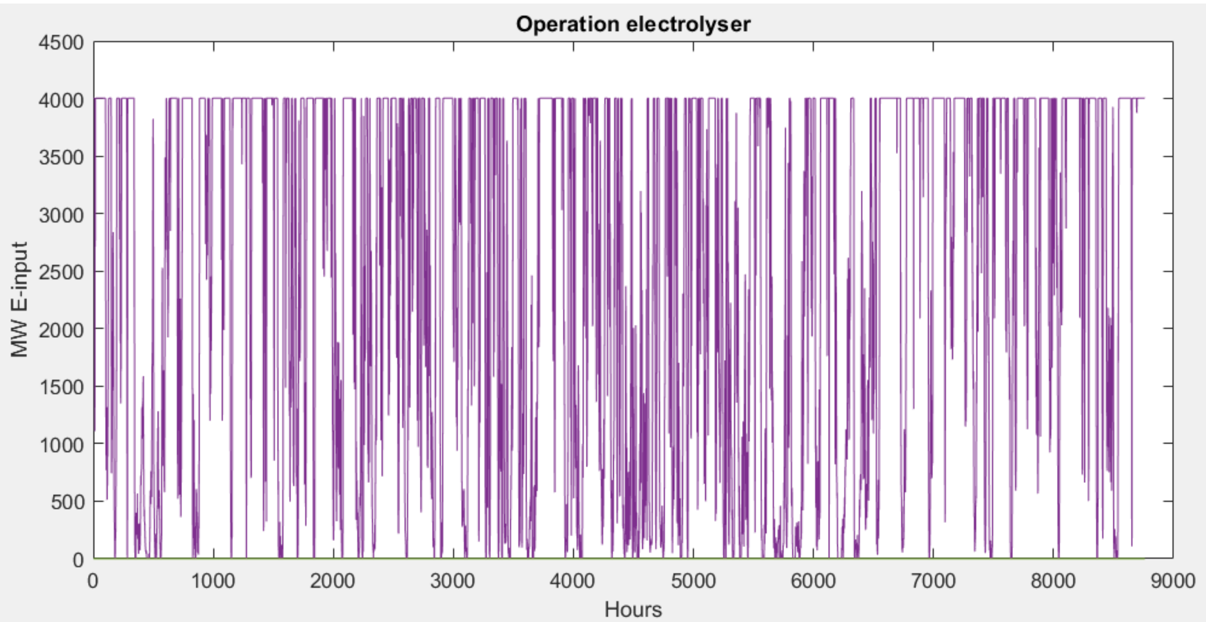

Figure 5.11: Market following production profile for Hub East scenario 2.

5.2.4 International integration

The location of Hub East is very close to the German offshore area. Actually, a significant share of the German offshore area is located closer to the Dutch shore than the German shore, making it interesting to connect German windparks to the Dutch shore as well via electricity interconnections. The option of an energy island that is proposed in storylines 1 and 2 make Hub East ideal to provide such electricity interconnections.

With regards to potential interconnections for hydrogen, it can be concluded that there are not esting pipeline sections that could connect Hub East to Germany. Hence, if hydrogen interconnections with Germany are perceived as favourable from Hub East, new pipelines have to be constructed.

5.3 Hub North

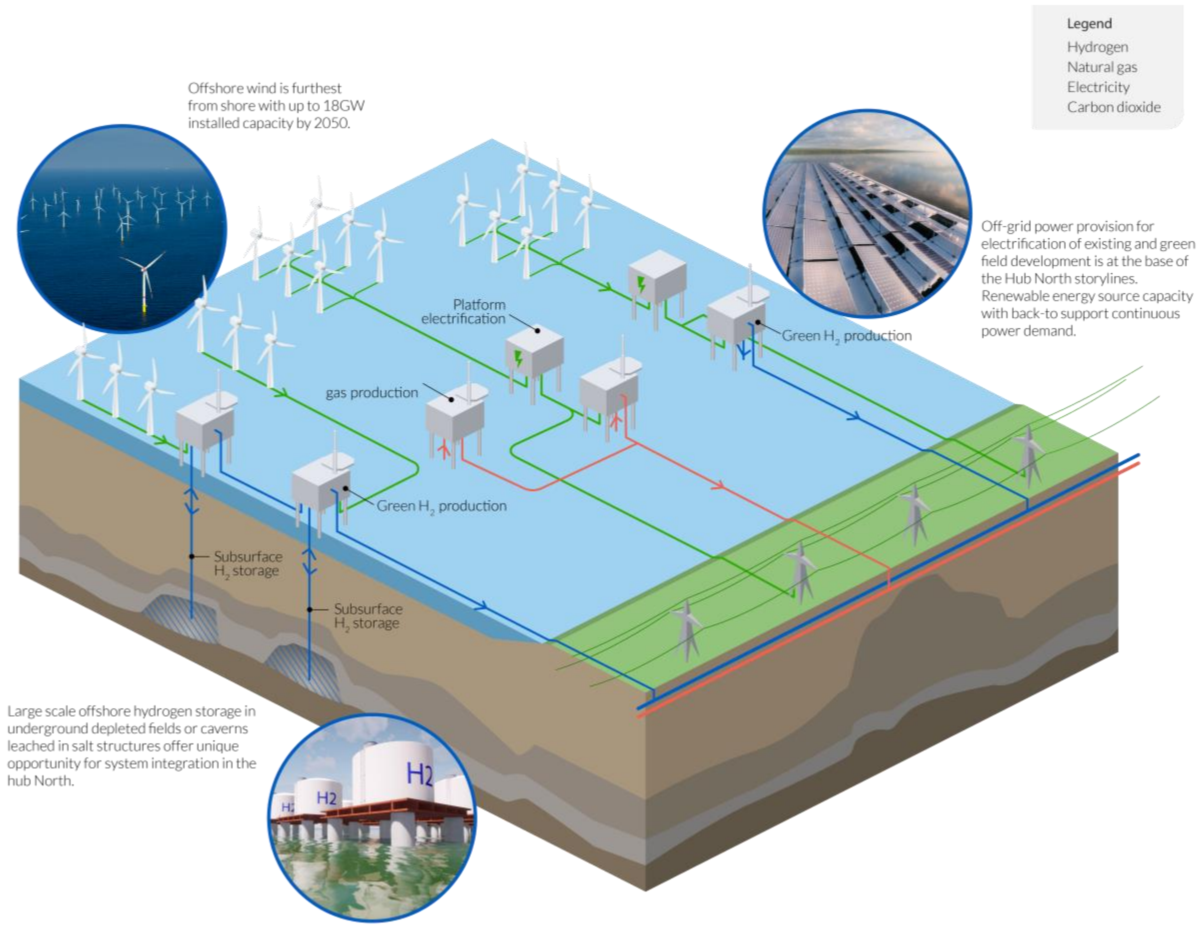

Figure 5.12 Schematic showing key elements of Hub North.

The storylines for Hub North consist of a series of common activities and characteristics which were presented in chapter two (See Figure 5.12 for a schematic of Hub North). An important element of this hub is to develop prospective gas/oil field infrastructures that can be sustainably deployed for future P2G facilities and transport networks. Thus, the storylines for Hub North are based on variations in the transport of hydrogen through new and existing pipelines. Table 5.3 summarises the KPIs for the various scenario results of Hub North. In order to provide an indicative NPR, electricity, hydrogen and methane prices generated by WP6 are used, resulting from the II3050 national scenarios. For platform electrification no revenues are assumed.

Table 5.3: KPIs Hub North

<table>
<tr><th>KPI</th><th>Storyline 1</th><th>Storyline 2a</th><th>Storyline 2b</th><th>Storyline 3</th></tr>
<tr><td>Maximum annual (and cumulative) CH4 production</td><td colspan="4">5.4 bcm/a (64.1 bcm)</td></tr>
<tr><td>NPC CH4 production</td><td colspan="4">0.93 B€</td></tr>
<tr><td>NPR CH4 production</td><td colspan="4">0.75 B€</td></tr>
<tr><td>UTC CH4 production</td><td>0.015 €/Nm³</td><td colspan="3">0.03 €/Nm³</td></tr>
<tr><td>Maximum annual (and cumulative) vol. offshore wind produced</td><td colspan="4">98.9 TWh/a (3065 TWh)</td></tr>
<tr><td>Maximum annual (and cumulative) vol. electricity landed onshore</td><td colspan="4">98.6 TWh/a (2946 TWh)</td></tr>
<tr><td>NPC offshore wind production</td><td colspan="4">16.3 B€</td></tr>
<tr><td>NPR offshore wind production</td><td colspan="4">29.3 B€</td></tr>
<tr><td>UTC offshore wind production</td><td colspan="4">37.4 €/MWh</td></tr>
<tr><td>UTC offshore transmission</td><td colspan="4">12.7 €/MWh</td></tr>
<tr><td>Maximum annual (and cumulative) vol. consumed for electrification</td><td>0.18 TWh/a (5.4 TWh)</td><td colspan="3">0.35 TWh/a (10.9 TWh)</td></tr>
<tr><td>NPC electrification</td><td colspan="4">224 M€</td></tr>
<tr><td>NPR electrification</td><td colspan="4">0 M€</td></tr>
<tr><td>UTC electrification</td><td>139.4 €/MWh</td><td colspan="3">85.2 €/MWh</td></tr>
<tr><td>Maximum annual (and cumulative) vol. H2 produced</td><td>0.44 Mton (13.8 Mton)</td><td colspan="3">0.43 Mton (13.4 Mton)</td></tr>
<tr><td>NPC H2 production</td><td colspan="4">7.1 B€</td></tr>
<tr><td>NPR H2 production</td><td colspan="4">4.7 B€</td></tr>
<tr><td>UTC H2 production</td><td>3.94 €/kg</td><td colspan="3">4.05 €/kg</td></tr>
<tr><td>UTC H2 transport</td><td>2.55 €/kg</td><td>2.75 €/kg</td><td>2.51 €/kg</td><td>2.73 €/kg</td></tr>
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Storyline 1: Focus on re-use of the existing infrastructure – effect on UTC of H2 transport

Using NoGaT, the blended gas stream is transported to Den-Helder, green molecules are separated, the natural gas is converted to blue hydrogen and CO_2. This storyline includes 250 km of reused NoGaT pipeline. Hence there will be an interaction with the CO2-storage network considered in Hub West and the greenfield production of natural gas. The NPC of the total system is about 34 B€. This NPC is the same for storylines 2 and 3 as well, except for the offshore hydrogen pipeline network. In this storyline the NPC of the hydrogen transport network resulted in 4.6 B€. The costs of re-using an existing pipeline are significantly lower than the NPCs in the other storylines, which involve making networks from existing pipelines or developing a new pipeline. Analysing both the production and transport capacities of hydrogen from Hub North, it becomes clear that the 36-inch NoGaT pipeline (>12 GW) has already enough capacity to transport the produced hydrogen by the assumed 8 GW of electrolysis capacity located in Hub North towards shore. Therefore, the additional pipeline capacities assumed in storyline 2a, 2b and 3 could be added advantage compared to scenario 1 for even larger scale electrolysis and/or international interconnection capacity. However, if in the future additional electrolysis capacity will be established even further offshore and/or significant volumes of hydrogen are transported via interconnectors towards Hub North, larger transport capacities are required and storyline 2a, 2b and 3 can be taken into account. Another consideration is if the NoGaT has still to be utilized for natural gas, storyline 3 takes into account co-use of NoGaT in combination with a new pipeline dedicated for hydrogen.

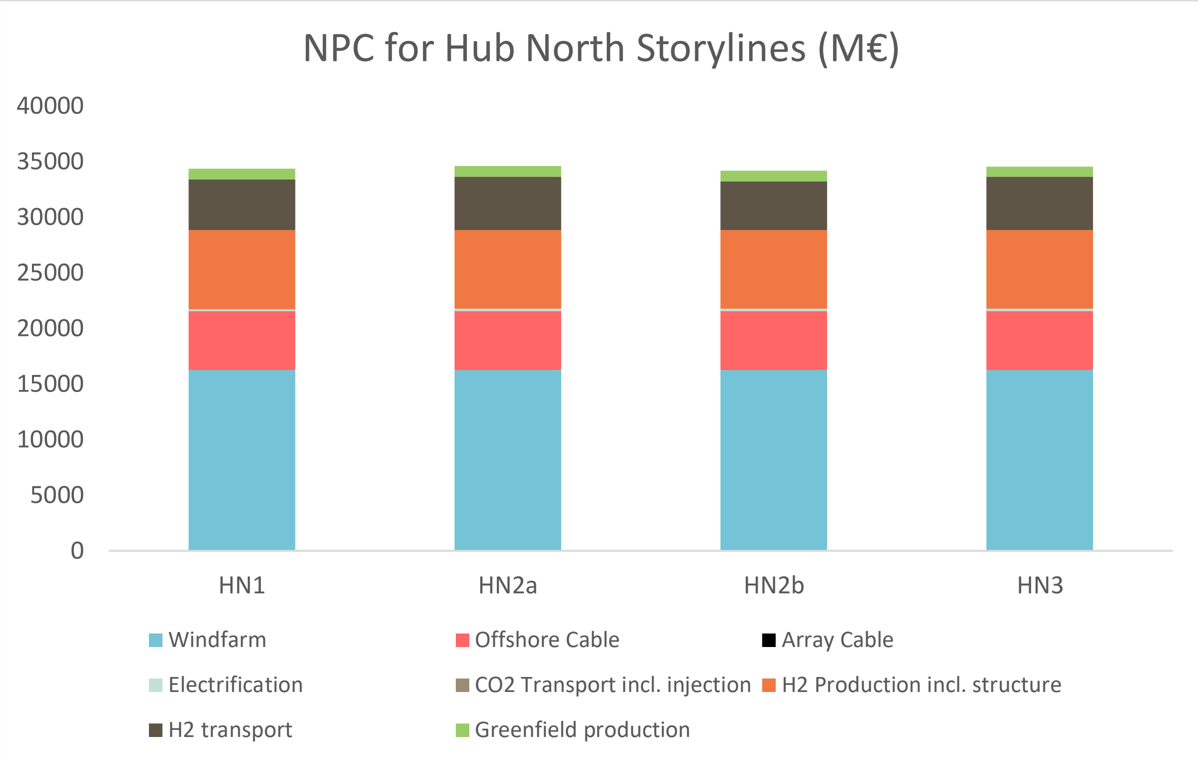

Figure 5.13: Total NPC Hub North storylines 1, 2a, 2b and 3

Storyline 2: Focus on making a network of existing infrastructure - effect on UTC of H2 transport
A new side connection (250 km, 48 inch) with NGT will be made via areas 6 & 7 to the G17 platform located in Hub East. Hub North activities will interact with the P2G activities in Hub-East. This new pipeline – and the NGT – will be transporting pure H2. Compression of H2 will be occurring on the G17 platform. The NPC of the total system is about 34-35 B€. The NPC of the hydrogen transport networks based on existing pipelines resulted in 4.8 B€ (2a) and 4.4 B€ (2b).

Storyline 3: New pipeline – effect on UTC of H2 transport
Instead of utilizing existing pipelines, a new 48" pipeline is installed over a distance of 250 km with a maximum capacity of 12 GW. This new pipeline transports pure hydrogen and is a nexus for the Dutch Continental Shelf with other regions. The NPC of the total system is about 35B€. The NPC of the hydrogen transport network, which relatively involved a large share of new pipelines, resulted in an NPC of 4.8 B€.

In the following section these parameters will be discussed in further detail and compared to – there where possible – with industrial insights.

5.3.1 Platform electrification without a network

Platform electrification without a connection to shore can only be realised if a continuous power supply of power – given the intermittency of the wind, solar and wave resources – with an offshore back-up system is in place. To balance the seasonal production of offshore renewable energy resources and the continuous demand for offshore power, a combination of lithium-ion battery options as well as back-up provision by a fuel cell is considered. The battery systems provide daily balancing support, whereas the fuel cell provides balancing support for the seasonal variations in productions. The winter seasons relatively higher production volumes of wind and wave are expected, whereas floating solar has higher production volumes during summer. The below exercise is a first indication of how such a system may look like, though, note that this system is not optimised nor from an economic point nor from a technical point of view.

The base case – the blue line in Figure 5.14– illustrates a situation in which the power facility (with a stable demand pattern of 20 MW) is supplied via direct power from offshore production resources (a combination of wind (45 MW, solar (30 MW) and wave (30 MW)) and indirect power output via coupled battery capacity of 30 MW & 300 MWh, Electrolyser capacity of 45 MW, fuel-cell capacity of 20 MW, and a storage tank of 1500kg. The base case clearly shows a clear increase in shortage of power supply over the summer period (rapid increase between 2000&6000 hours). At the same time – given the amount of overcapacity – more electricity is available over the course of the year, and a great part of the electricity can be converted into hydrogen and shipped to shore once the H2 storage tank is full. Figure 5.15 displays the oversupply of electricity over the course of one year. By converting the electricity into hydrogen additional revenues can be generated.

A couple of solutions can be considered to overcome such shortage:

- More RES production over summer periods. A triple increase in the floating solar capacity (see red line) near the platform reduces the shortage to consumption significantly. A further increase in solar capacity is expected to dampen the shortage even further, though, simultaneously will lead to higher volumes of electricity oversupply. The solution would go hand-in-hand with an additional investment of 40M€
- Significant more offshore storage of hydrogen as a back-up source (green line) with additional investments of some 80M€. A 300% increase in storage capacity is almost supporting a continuous power supply to the offshore facility. This would imply that depleted gas field/offshore salt formations nearby should accommodate such storage. By prioritising storage above transport of hydrogen to shore, lower revenues from this part can be expected.
- At last, more flexibility of power demand over summer periods. A reduction of power demand – e.g. from 20 MW to 15 MW over summer periods – would reduce the shortage of consumption, this would however apply that the offshore facility can handle such flexibility. It is expected that the oversupply function is not affected by more flexible offshore power intake.

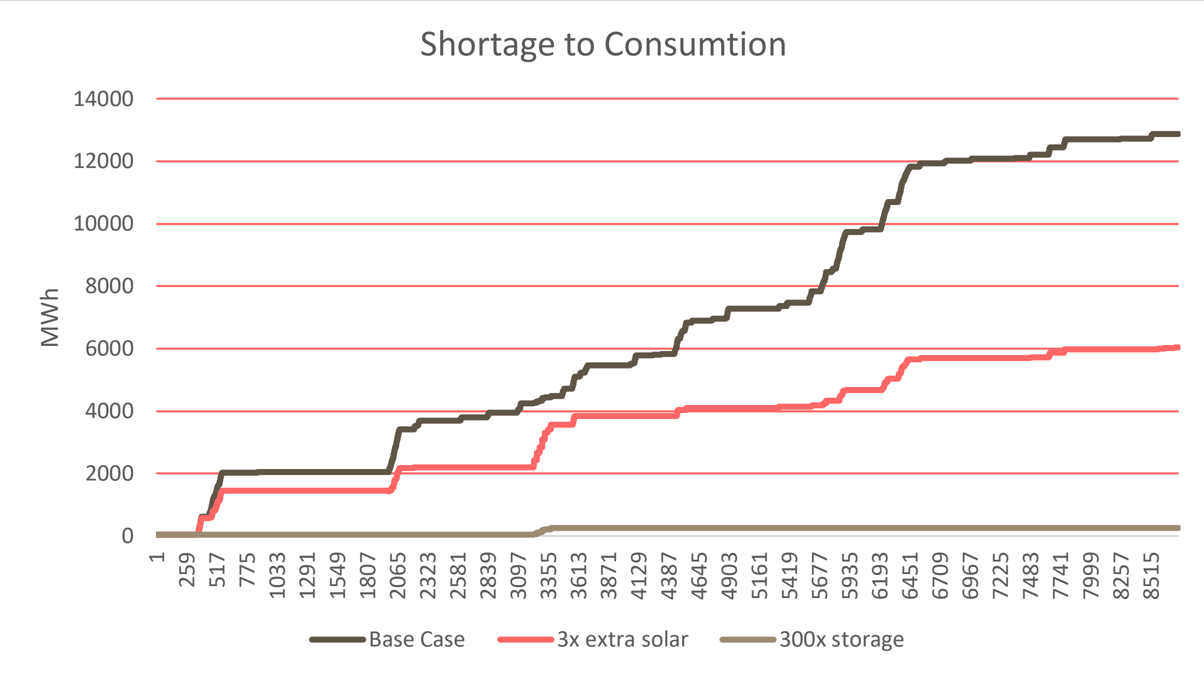

Figure 5.14: Shortage to consumption and back-up requirements to facilitate offshore off-grid continuous power consumption

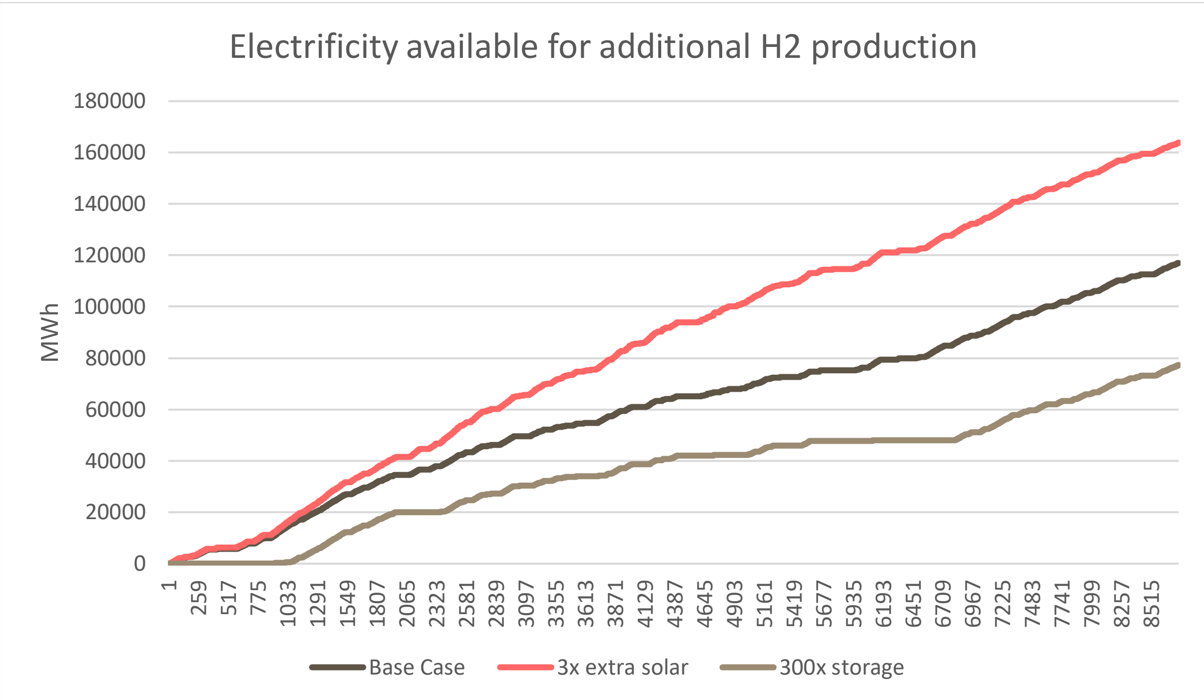

Figure 5.15: Additional electricity available for H2 production and transport to shore

The total investment costs of standalone electrification is some 352M€ and operational expenses (fixed and variable) are about 14M€. Figure 5.16 highlights the distribution of the costs over the various assets involved. Operational expenses do not involve any of the losses involved in storage and conversion. Nonetheless, back-up facilities – the combined used of lithium-ion batteries and H2 storage – comprises of about a third of the investment costs.

The investments for standalone electrification are significantly higher (a factor 4 to 7) than investments required for electrification via a grid connection as indicated in the Hub West and Hub East region.

Though, the additional sales from hydrogen production leads to an additional annual profit of about 7M€[23].

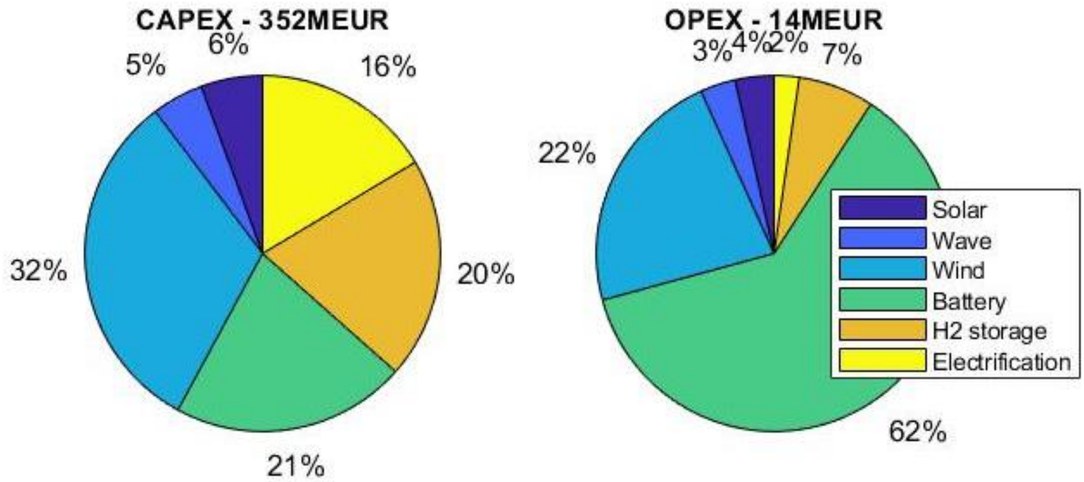

Figure 5.16: Distribution of costs standalone electrification (CAPEX and OPEX)

Further research would be needed to optimise the configuration of assets to support off-grid power consumption as well an indication what storage and conversion capacities could fit on the existing offshore facility.

5.3.2 Greenfield Natural gas production

Electrification in Hub North does not take place via an integrated power network but via direct 66kV cables with a capacity of 30 MW and length of 5km connected to their respective substations. The F3 and F6 platforms will be connected to a substation located in future wind-farm areas 6 and 7 in the Dutch continental shelf. It is expected that these windfarms will commence operation in 2031 with an initial capacity of 2 GW and an extra 2 GW of added capacity per year which will eventually result in a peak capacity of 18 GW by 2039 and will continue operation until 2048. There will be oil and gas production in F-blocks: F3-B, F15-FA and L2. The production sites are connected to the shore via the NoGat pipeline (36”) to Den Helder. NoGaT can bring natural gas, blended gas streams and pure H2 to landfall points.

5.3.3 International Integration and P2G wind following vs. market following

Due to its central location on the North Sea, Hub North has a large interconnection potential with actually all the North Sea countries: the UK, Norway, Denmark and Germany. This international connectivity of actors in Hub North can be exploited by acting upon variations in electricity and hydrogen market prices between various North Sea energy markets. The load factor for market following hydrogen production is some 20% below the load factor of dedicated hydrogen production. This process can be optimised by coupling additional markets (in this case) Germany, Denmark, Norway and the United Kingdom or by offering additional services (e.g., frequency control).

There are several existing pipelines that can be considered to realise hydrogen interconnections from Hub North. In the following sections, these options will be discussed in greater detail.

[23] Assuming a market price of hydrogen of about 80€/MWh

5.3.3.1 Hydrogen interconnection with the UK

Net Zero Technology Center has performed hydraulic analysis of the routes for green hydrogen export to/from UK to Netherlands using existing infrastructure. Due to the geographical location and identified existing infrastructure, Bacton has been selected as the primary reception point in the UK and Den Helder or Uithuizen Gas Plant in the Netherlands. Theddlethorpe and Easington have also been included as options for the UK reception facilities. Following options were identified for –

Storyline 1:

- Proposed new build pipeline routing from platform F3 to Bacton
- Proposed new build pipeline routing from platform F3 to Bacton via UKCS infrastructure

Storyline 2:

- Proposed new build pipeline routing options from the Wingate facilities at the end of the NGT pipeline system to Bacton, Theddlethorpe and Easington.

The new pipeline routings for each storyline are displayed in Figure 5.17. The corresponding line size is tabulated in Table 5.4 Summary of routing and hydraulic analysis results. The inlet pressure at NOGAT/F3 and NGT/G17 is assumed 120 bara and the flowrate max/min is assumed 24.3/43.1 MMSCM/d. Outlet pressures on arrival to the UK vary from 57 to 108 bara for Storyline 1 and it is set at 50 bara for Storyline 2 to maximize the flowrate.

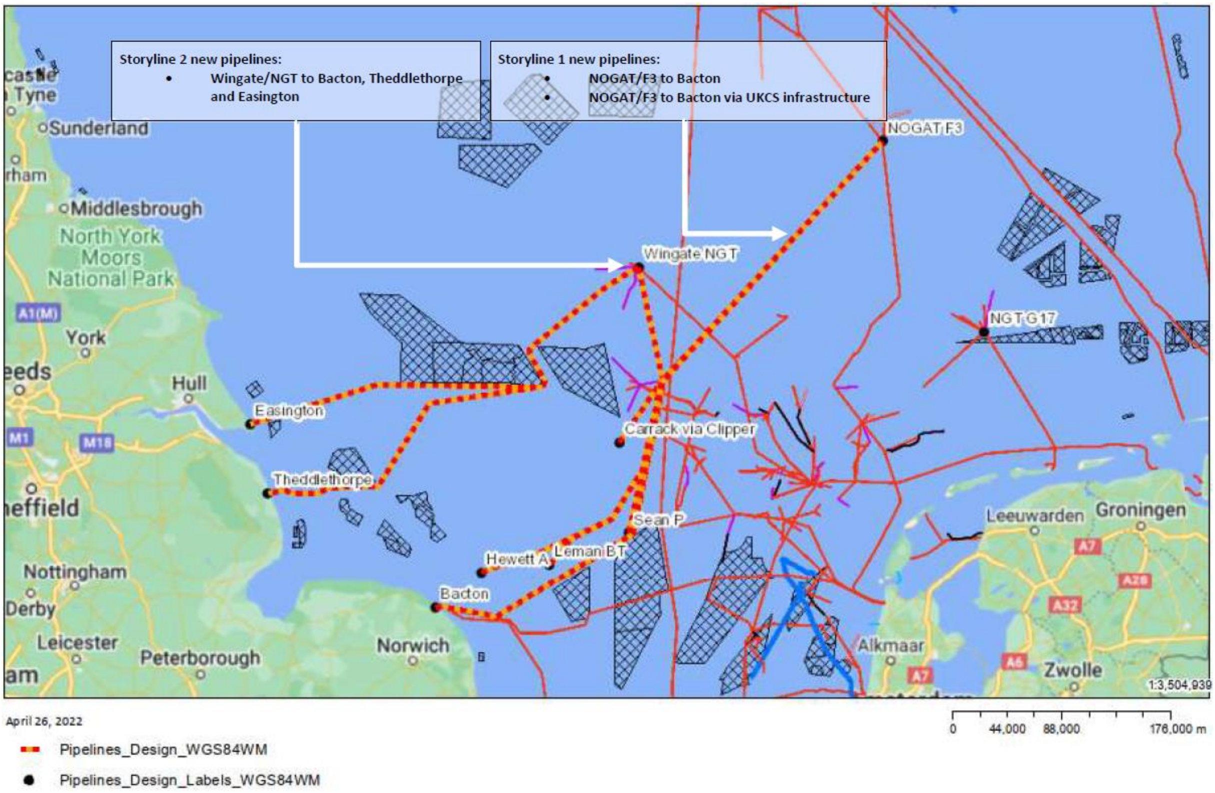

Figure 5.17 Pipeline routes for green hydrogen export to/from UK to Netherlands using existing infrastructure.

Table 5.4 Summary of routing and hydraulic analysis results

New Pipelines		Sizes (inch)
Storyline 1	F3 to Bacton (A1)	30
	F3 to Hewett A (B1) 28	28
	F3 to Leman BT (C1)	28
	F3 to Carrack (D1)	28
	F3 to Sean P (E1)	28
Storyline 2	Wingate to Bacton (A2)	30
	Wingate to Theddlethorpe (B2)	30
	Wingate to Easington (C2)	30

5.3.3.2 Hydrogen interconnection with Norway

Norway has a vision of being the energy hub of the future. One of the activities within this vision is becoming a net exporter of hydrogen. The main contributor of this export might become blue hydrogen. Currently, there is looked to a project to install a blue hydrogen production plant of 1-2 GW before 2030, which could be expanded towards 10 GW in 2038. In between this period, at least 1.5 GW of green hydrogen production capacity is aimed to be developed.

The export of hydrogen towards Europe could be fulfilled via one of the existing natural gas interconnectors, for example the Europipe or the Europipe II.There could be started to provide blended natural gas and hydrogen streams via one of these pipes and at 2040 a 100% stream of hydrogen can be delivered. The NoGaT could be connected with the re-used pipeline in order to make the actual connection with Hub North. Another option of consideration is to construct a new interconnector pipeline, which is significantly more expensive but if the existing pipelines are still in operation for natural gas than re-use is not an option.

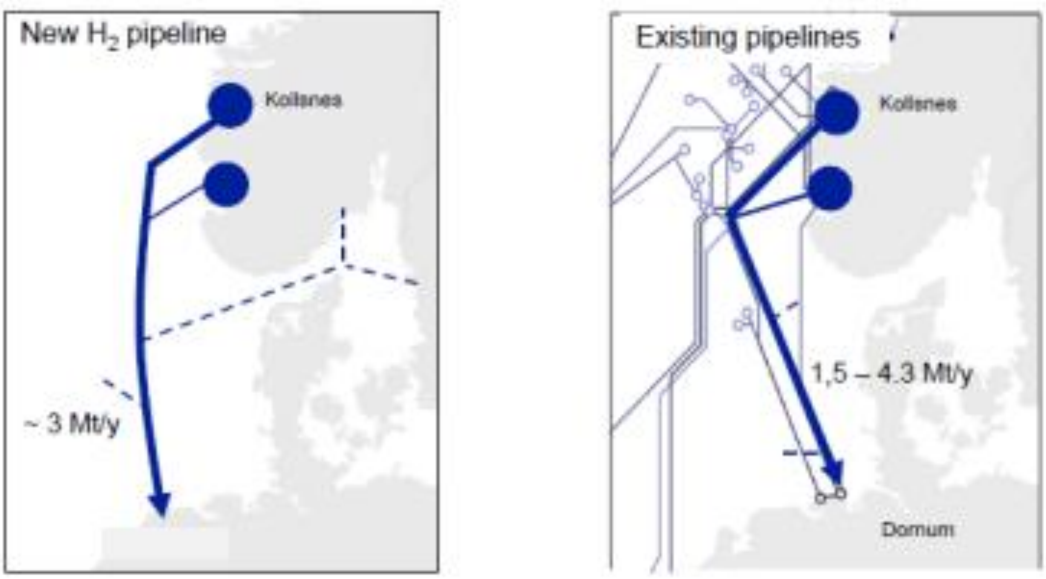

Figure 5.18: Vision on potential hydrogen import routes from Norway (55)

5.3.3.3 Hydrogen interconnections with Germany and Denmark

Another option for hydrogen interconnections by reusing pipelines are Germany and Denmark. Although no conversations have been taking place with potential projects that aim to re-use these pipelines. The interconnection with Germany can be established, similarly to the Norwegian connection, by connecting the NoGaT pipeline with the Europipe or Europipe II.

Secondly, Hub North could be connected to Denmark via the 32 inch Tyra-Nybro offshore pipeline. This could be part of an even further integration of the North Sea within the European energy system. For example, via the investigated Baltic Pipe project, which could be an option to connect Denmark and Poland.

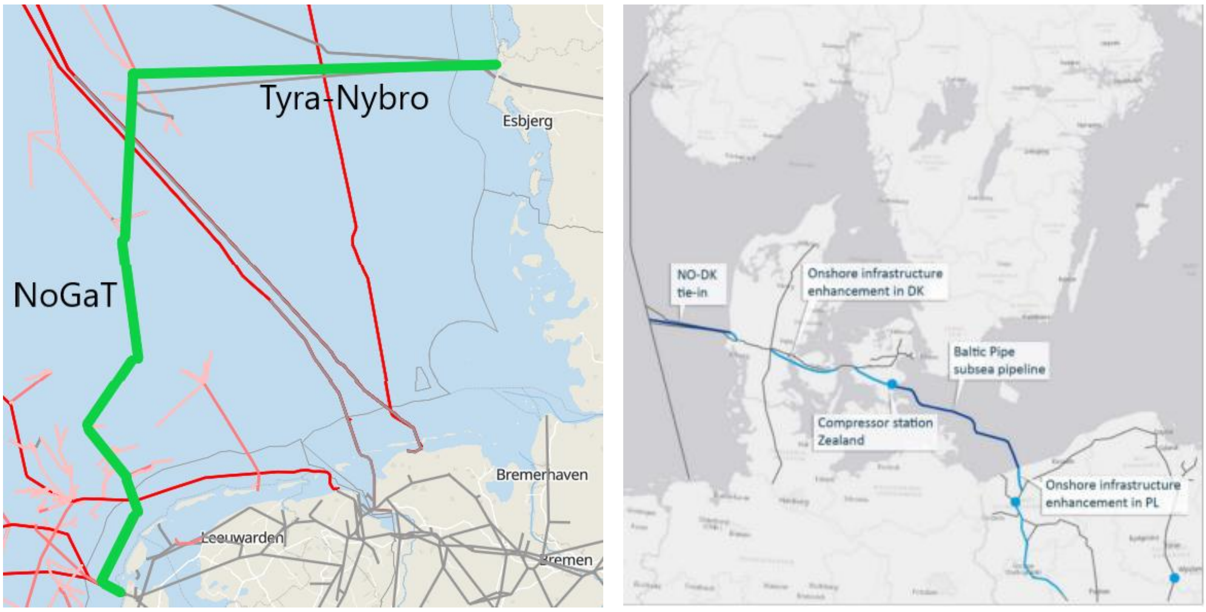

Figure 5.19: Geographical locations of existing offshore pipelines that interconnect Hub North

5.4 Interconnected hubs

The three energy hubs, although physically separate are interconnected via the transport pipelines. As hub West, East and North develops, the interconnections between them will have to account for activities planned within each hub.

As discussed in section 2.5, the interconnected hub storylines are the combination of all storylines 1 for hub West, East and North, and so on. The indicators of developing the three hubs combined for each storyline are shown in the table below.

Table 5.5: KPIs Interconnected Hubs

KPI	Storyline 1	Storyline 2a	Storyline 2b	Storyline 3
Maximum annual (and cumulative) vol. offshore CO2 network	26.5 Mton/a (602 Mton)			
NPC offshore CO2 network	0.5 B€			
UTC offshore CO2 network	3.3 €/ton	2.9 €/ton		2.8 €/ton
Maximum annual (and cumulative) CH4 produced	7.4 bcm/a (78 bcm)			
NPC CH4 production	1.75 B€			
NPR CH4 production	1.53 B€			
UTC CH4 production	0.04 €/Nm³			
Maximum annual (and cumulative) vol. offshore wind produced	160 TWh/a (4986 TWh)	179 TWh/a (5590 TWh)		169 TWh/a (5277 TWh)
Maximum annual (and cumulative) vol. electricity landed onshore	109 TWh/a (3261 TWh)	128 TWh/a (3831 TWh)		118 TWh/a (3528 TWh)
NPC offshore wind production	31.5 B€	37.8 B€		35.2 B€
NPR offshore wind production	55.0 B€	64.8 B€		60.6 B€
UTC offshore wind production	38.6 €/MWh	40.0 €/MWh		39.1 €/MWh
UTC offshore transmission	13.7 €/MWh	13.4 €/MWh		13.3 €/MWh
Maximum annual (and cumulative) vol. consumed for electrification	0.53 TWh/a (10.7 TWh)	0.97 TWh/a (18.1 TWh)	1.20 TWh/a (18.9 TWh)	
NPC electrification	271 M€	543 M€		604 M€
NPR electrification	0 M€			
UTC electrification	74.2 €/MWh	94.2 €/MWh	87.2 €/MWh	96.8 €/MWh
Maximum annual (and cumulative) vol. H2 produced	1.46 Mton (45 Mton)	1.20 Mton (37 Mton)		1.50 Mton (46 Mton)
NPC H2 production	13.4 B€	18.0 B€		20.0 B€
NPR H2 production	22.2 B€	15.5 B€		20.4 B€
UTC H2 production (excl. electricity costs)	1.56 €/kg	2.88 €/kg		2.44 €/kg
UTC H2 transport	0.96 €/kg	1.24 €/kg	1.17 €/kg	1.09 €/kg

Figure 5.20 shows that developing the three offshore energy hubs combinedly would result in an NPC of 62 and 75 B€. To give an indication on the volumes of energy that are generated in these hubs: at the peak of its installed capacity, it would deliver approximately equal amount of electricity as the Netherlands consumed in 2021 (122 TWh (56)) and approximately 82% of the Dutch demand for hydrogen in 2019 (57), or 10% of the energy content of demanded natural gas in the Netherlands in 2021 (which was around 400 TWh (58)). Besides the volumes of produced renewable electricity and hydrogen, also a significant amount of greenfield natural gas production (18.5% of the 2021 Dutch demand (58)), CO_2 storage (19% of the 2021 Dutch emissions (59)) and platform electrification is applied in each of the storylines. Thereby, the offshore hubs do unlock the potentials of developing more renewable generation sites further from the shore, providing interconnections to balance future energy flows and to create the synergies that help to deal with spatial issues.

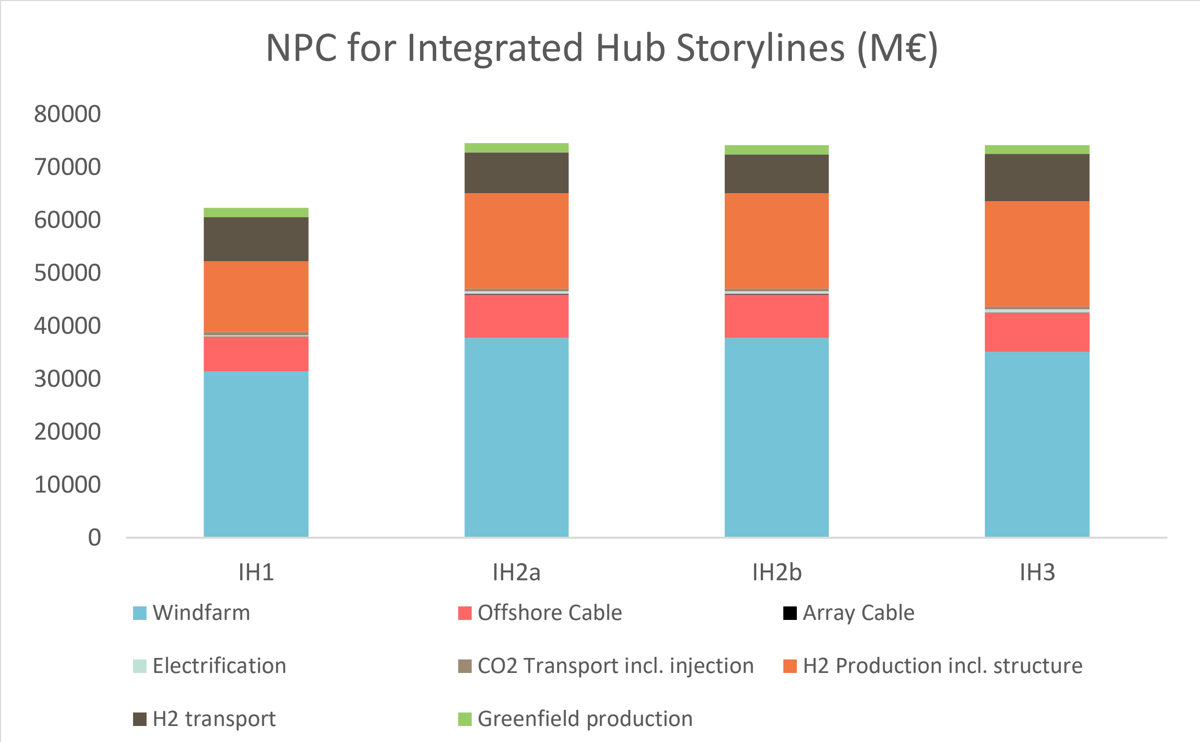

Figure 5.20 NPC for integrated hub storylines

5.5 Indicative spatial impact North Sea Energy activities in harbours

Based on input of the Dutch harbours of Rotterdam, Amsterdam and Den Helder an indicative investigation is made on the spatial impact of North Sea Energy activities, of which the complete methodology and assumptions are described in Appendix E. Two scenarios are developed for the landfall of renewable energy in the coming decades. The 'Concentrated' scenario assumes that the majority of the energy would land in the Port of Rotterdam, while the 'Spread' scenario assumes that the landfall is organised more distributed. The figures below give an overview of the spatial impact in the different harbours over the years. In the figures only the minimum considered space requirements are shown for each scenario, which are 232 hectares. The maximum considered space resulted in 267 hectares. The actual space requirements will depend hugely on the degree in which energy will land in the form of electrons or molecules: landfall of energy in the form of electrons will occupy 5-8 times as much space as in the form of hydrogen molecules. The figures only contain the space requirements for landfall of energy and therefore exclude space requirements for other offshore energy related activities, such as maintenance activities.

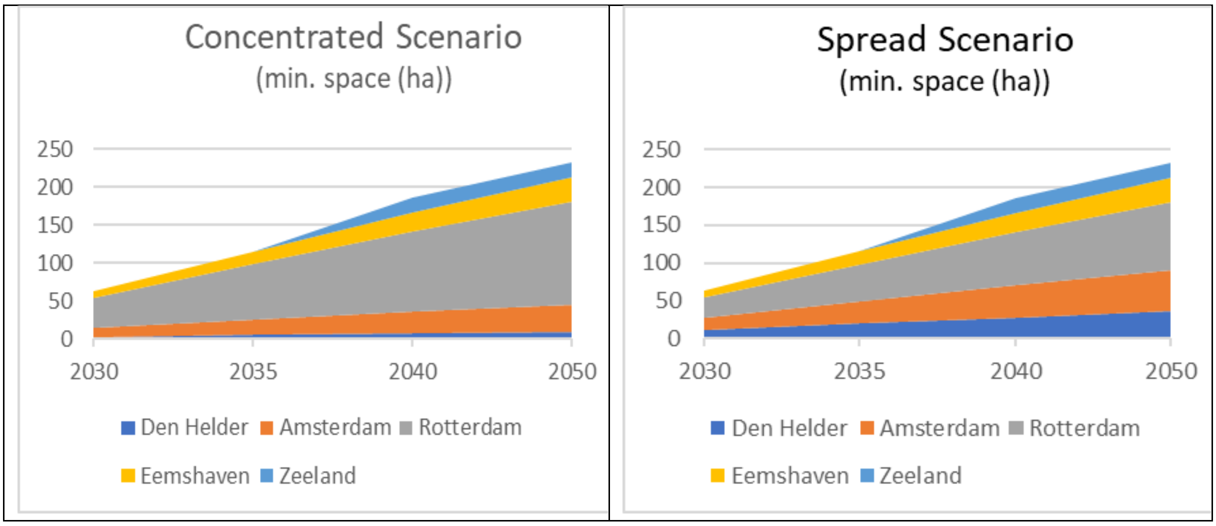

Figure 5.21 Spatial impact on harbours (left) under concentrated scenario and (right) spread scenario

Both the Concentrated and Spread scenarios demand for space requirements at ports which will be challenging to realise. Hence, the available space for landfall in ports is a constraint that should be considered very carefully in the integration of the onshore and offshore energy system. Therefore, it is important that:

- Landing locations and transit locations are integrally included in the planning and design of the offshore energy system. Coordination between harbours is required to manage this issue. This applies to all commodities, with emphasis on wind and hydrogen. A long-term vision of the North Sea activities must be maintained to take into consideration activities like recommissioning of existing and future wind farms.
- The demand for space in ports to support the energy transition is enormous. The distribution scenario requires coordination and the connection between the ports. In addition to the H2 backbone, the electricity system (TenneT vision) must also be properly connected. This must be linked to the security of supply and security for wind farms. In addition to system technical gains, the diversification scenario can also yield economic gains.
- The landing of molecules (H2) has a lower spatial impact than electrons (electricity). This can be an important factor in the timely realization of the offshore energy transition and contribute significantly to the security of supply. However, possible additional gains from onshore conversion (reuse of residual heat and oxygen) must be taken into account.

6 Taking actions towards offshore energy hubs

6.1 Analysing information interdependencies between activities

Many technical energy-related systems are involved in the development of renewable energy hubs in the North Sea region. The four main systems are:

- current and future natural gas exploitation (NG)
- current and future offshore wind farms (OWF)
- future hydrogen (H_2)
- future carbon dioxide (CO_2)

These systems will have to be developed as such that they all fit within one integrated energy system at the North Sea. The development of these different systems is taking place in parallel. This leads to inevitable information dependencies and interfaces between the system development activities. Knowing upfront which dependencies and interfaces will emerge will allow for timely interface management. And successful interface management can (1) increase the speed of the developments, (2) reduce conflicts between the different stakeholders involved (and goals to be reached), (3) increase the quality of the processes and assets developed, (4) decrease system development costs, and thus increase the overall effectiveness and efficiency of the energy transition on the North Sea as a whole.

Insights can be gained on the interconnectedness of the development of all those assets by looking into the information dependencies and activity interfaces. *The objective of this research activity has been to increase the knowledge level on system integration from an **activity** point of view*, and thereby contribute to the multi-system hub action plan(s) by providing insights in the relationships between the NG, OWF, H_2 and CO_2 system development activities. Based on these activities generic cases are defined, of which their relevance per hub is shown in the table below.

Table 6.1 The relevance of the five cases for the different hubs.

		Case 1 **OWF required for H2 production & NG electrification**	Case 2 **Lifetime extension of natural gas exploitation platforms blocks reuse of infrastructure**	Case 3 **Clarity on reuse purposes NG pipeline to start CO2 or H2 admixing refurbishment**	Case 4 **Offshore electrolysers FID**	Case 5 **CO2 storage demand and FID**
Hubs and their storylines	<u>**Hub West**</u> *P2G on a sandy island.* *Dedicated P2G on multiple platforms.* *Dedicated P2G on multiple platforms and flexible P2G at single platforms.*	**Relevant**, though only for the production of H2 (platform electrification through offshore wind electricity for gas production and CCS only is not considered).	**Not relevant** (platform electrification through offshore wind electricity for gas production and CCS only is not considered)	**Relevant**, as existing pipelines are considered in the modes of transport,	**Relevant**	**Highly relevant** (storage potential for CO2 is very high)
	<u>**Hub East**</u> *Dedicated P2G on a sandy island.* *Flexible P2G on a sandy island.* *P2G on multiple platforms.*	**Relevant**, both for H2 production and NG electrification	**Not relevant** (only Greenfield gas platforms included in scope)	**Relevant**, though only for admixing in existing pipelines (no CO2 transport)	**Relevant**	**Not relevant**
	<u>**Hub North**</u> *Focus on re-use of the existing infra.* *Focus on making a network of existing infra.* *New pipelines.*	**Relevant**, both for H2 production and NG electrification	**Highly relevant** – electrification of existing platforms will occur in an early stage	**Highly relevant** (focus on re-use of existing infra is one of the storylines)	**Relevant**, as large scale hydrogen will be produced on multiple platforms	**(Probably) not relevant**, only CO2 transportation (connection to hub West).

6.1.1 Case 1: OWF required for H2 production and NG electrification

To enter the operational phase, a green hydrogen production system requires electricity (from offshore wind farms) to power the electrolysers and auxiliary subsystems. And as a prerequisite to access that renewable power, the electricity transport infrastructure needs to be in operation. This implies a sequence in asset commissioning on the North Sea.

Operation of electrified natural gas platforms have similar dependencies: the need for renewable power can be fulfilled if both the OWF and the electricity transport infrastructure is operational. To this end, both the hydrogen production system and the natural gas production systems depend on the timely commissioning of the complete offshore wind farm system and power transport system.

The vicinity of supply, transport and demand systems plays a major role in the possibility to integrate OWF, H_2 and NG systems: the *decisions on wind farm development areas* (part of the OWF orientation phase) determine the extent to which integration with hydrogen production systems or gas platforms is attainable. The *power demand, timing and feasibility* of platform electrification, hydrogen production and CO_2 storage subsequently determines the (industrial) need to utilize the power on-site at the North Sea. And the local power 'consumption' needs *influence the need for electrical infrastructure* to shore and thus the lead-time of the OWF system.

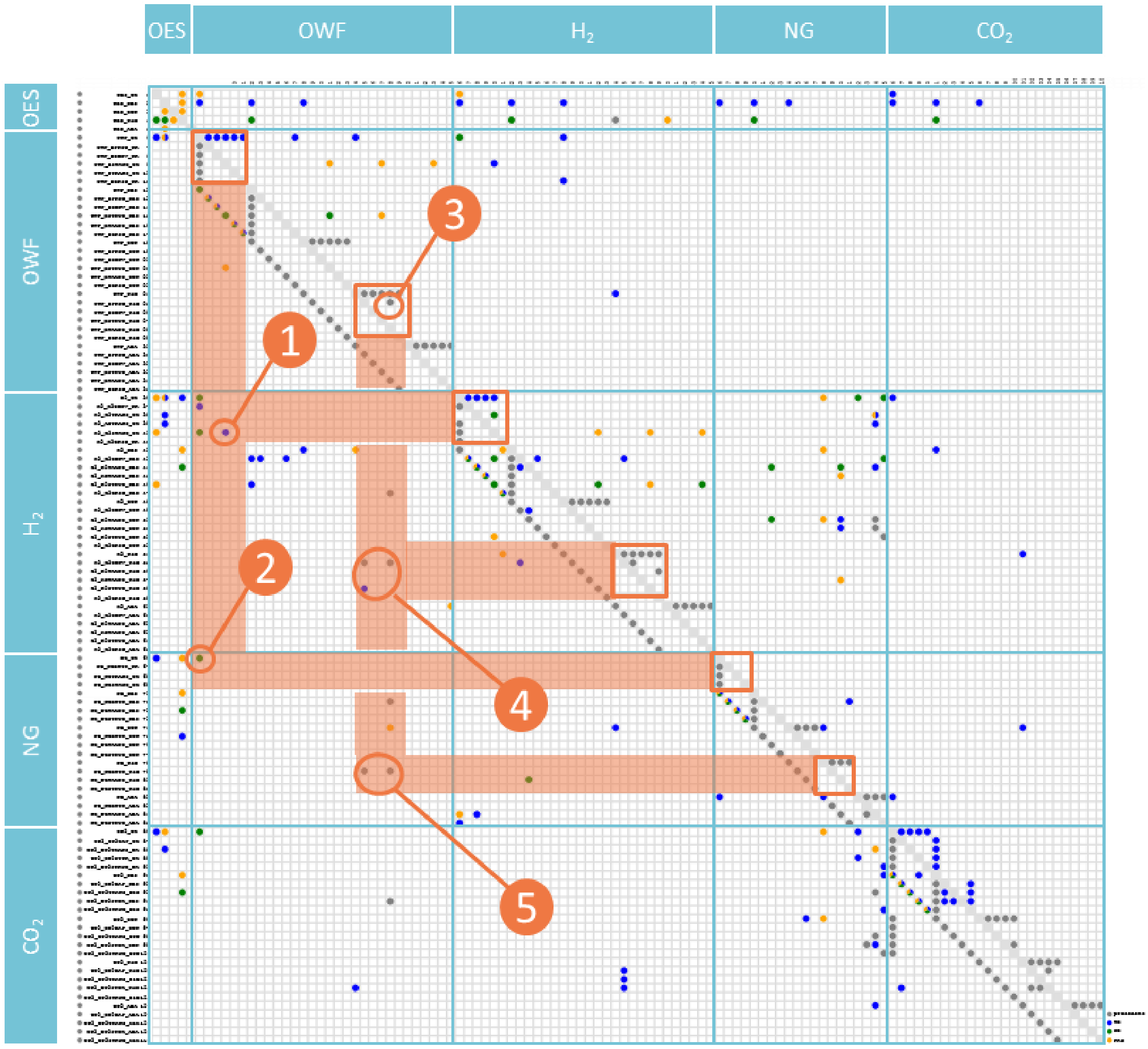

Figure 6.1 For illustration: The DSM containing interdependencies between the offshore wind farm and the hydrogen production system and natural gas platforms respectively (case 1)

6.1.2 Case 2: Lifetime extension of natural gas exploitation blocks by reuse of infrastructure

The second case relates to the required decision <u>*when*</u> *to re-use existing natural gas pipelines, wells and platforms.*

The extent to which natural gas extraction from wells on the North Sea is continued in the future determines to a large extend the possibility of re-using those assets for new purposes: H_2 or CO_2 production and/or storage and transport to shore or neighboring countries. The timing of pipeline, well and/or platform asset repurposing therefore depends on the natural gas production forecasts, permits to operate and (inter)national policies that set natural gas production targets.

Extension of NG exploitation timelines therefore delays repurposing pipelines, wells or platforms and consequentially delays the commissioning date of CO_2 storage and/or H_2 production systems that depend on to-be-repurposed pipeline infrastructure. The effort to benefit from the merits offered by re-using natural gas assets may thus lead to a slower energy transition on the North Sea.

6.1.3 Case 3: Clarity on reuse purposes of NG pipelines

The third case relates to the required decision for <u>which purpose</u> *existing natural gas pipelines are to be re-used*: CO_2, pure hydrogen or admixed hydrogen. The decision on how to repurpose the infrastructure is inevitable, as only one new role can be assigned to the pipelines. *Pipelines for CO2, H2 or admixed hydrogen require different pipeline performance characteristics*, meaning that NG pipelines may be reused for either CO2, H2 or H2 admixing purposes, or may not be suitable for re-use. Therefore, the orientation, design and construction of CO_2 , H_2 or admixed H_2 transport infrastructure depends strongly on how, when and which pipelines currently in use for natural gas transport are abated and whether that *NG pipeline performance characteristics are such that the pipeline can be modified for a specific type of reuse*.

The interdependencies regarding this re-use decision is illustrated in the DSM: Information regarding the NG pipeline performance characteristics and abatement timelines flows from the natural gas operation & maintenance phase and abatement phase towards the CO_2 , H_2 or admixed H_2 orientation, design and construction phases. And decisions on preferred *re-use purposes are guided by offshore energy system level policies.*

6.1.4 Case 4: Final investment decisions (FID) for offshore electrolysers

The design phase activities of the hydrogen conversion subsystem includes making the Final investment decision (FID). The FID is commonly made only with a positive cost-benefit balance for its owner. The *information inputs required for a FID by that H2 conversion system owner are* originating from a wide range of activities on the North Sea, amongst which:

- The design of the offshore wind farm that provides the *power supply* profile that should fit the power demand profile of the envisioned electrolyser design. The designed power profile of the OWF on its turn depends on decisions made within the design phase of the wind turbine generators and the electricity conversion and transportation assets.
- The power production and transportation design activities will also indicate the possible design options to add *back-up electricity capacity solutions*, as part of the H2 system design, to maximize the operational hours of the hydrogen system.
- Increased insight in the revenue uncertainty on *long-term H2 product demand*, through future energy system simulation and scenario studies, can improve the understanding of uncertainty and thus investment risks and facilitate the FID.
- *Production locations of wind farms* leads to clarity on preferred offshore structure design (e.g. island, new platform, re-used platform), multi-purpose land use options and the implied investment costs and ease of phased investment in electrolysis capacity.

6.1.5 Case 5: Final investment decisions (FID) for CCS

The fifth case concerns the interdependencies that exist for making a final investment decision on the development and installation of CO2 capture and storage systems. One can see for Figure Y that the decision to invest in CSS (as part of the design phase of CO2) serves as the starting point for investments in the individual subsystems (1). This final investment decision takes into account the market demand for CO2 storage: stakeholders should commit to the storage of CO2 undergrounds to make an investment for the development and installation of a new CO2 capture and storage system worthwhile. It should therefore be apparent how much CO2 will be stored over time to motivate this decision making. Once the final investment decision is made, the investments for its subsystems (e.g. transportation via pipelines, platform structure) can start, taking these parameters into account.

On the other hand, we see that the design parameters of the individual subsystems also influence whether a final investment decision for the entire CCS system can be made (2). For example, the design parameters for CO2 storage or CO2 transportation provide input to the 'value' of the CCS system to potential market stakeholders. For instance, the parameters set for CO2 storage influence the amount

of CO_2 that can be stored for the system. This in turn influences whether the final investment decision for the CCS system as whole can be made.
As a result of these interdependencies, a classical *chicken-egg* problem emerges: the final investment decision for the CCS system influences how individual subsystems for the CCS system are to be developed. This final investment decision is dependent on market demand for CO_2 storage. However, the parameters for the individual subsystems influence what amount of market demand can be expected, and therefore in turn affect the final investment decision for the CCS system. To break this stalemate, decisions should already be taken on the design parameters for individual subsystems of CCS, whereas (long-term) commitment should be pursued on how much CO_2 will be stored by market stakeholders.

7 Synthesis and Outlook

The North Sea has transformative potential for the future of energy systems in Europe with vast offshore wind potential. Extracting maximum value from offshore wind requires an integrated approach to designing the coupling between energy sectors such as – hydrogen production on platform or island, energy transport (by pipeline or cable), electrification, greenfield development amongst many others. Offshore energy hubs offer a systematic framework to integrate various use functions in the North Sea. In this study, three offshore energy hub concepts in the North Sea were developed. The three hub concepts took into account the specific offshore environment and stakeholder presence in the West, East and North regions of the Dutch North Sea.

The energy hubs, as designed in this study, together contribute towards achieving approximately 34 GW Dutch offshore wind installed capacity by 2050. Offshore power to hydrogen platform and islands as the building blocks to scale the installed wind capacity to 70 GW by 2050 are conceptually described. Moreover, the three energy hubs will produce approximately 1.2 Mt/a Hydrogen and 181 TWh/a green electricity. Besides the total volume of hydrogen and green electricity, natural gas production is estimated to be 7.4 bcm/a (equivalent to ~19% of the 2021 Dutch natural gas demand). CO_2 storage is considered in several depleted fields in the North Sea, with the total CO_2 stored amounting to 27 Mt/a.

The insights generated from the hub scenarios can support informed decision making by industry and policy makers. The three North Sea Energy Hubs studied can, individually and in combination, be important stepping-stones for large-scale system integration in the North Sea and also offer insights for other offshore system integration projects globally.

Hub West

Hub West involved a common implementation of a CCS network through new/existing pipeline networks alongside platform electrification activities for the CO_2 injection platforms in all the hub scenarios. Around 600 Mt of CO2 are considered to be stored between 2025 and 2070 at a total NPC of 0.5 B€. 6.7-8.7 GW of offshore wind capacity is assumed to be installed and 4-5 GW of electrolyser capacity including both storylines with island and/or platform structures. The P2G production and structure costs were slightly higher for platforms (4.93 B€) as compared to islands (4.76 B€). Both re-use of the NGT and a new pipeline have been considered to bring the hydrogen towards shore. If the NGT is not used for any other offshore hubs, both options do not differ significantly in NPC. The total NPC to develop Hub West individually resulted in 14-22 B€. There is potential for at least electricity, hydrogen and/or CO_2 interconnections between this hub and the UK. If the Draupner-Duinkerke pipeline will be used for either hydrogen or CO_2 in the future, there might be an opportunity to connect to this network as well (France, Belgium and Norway).

Hub East

Hub East involved a common implementation of greenfield gas extraction, platform electrification, offshore wind production and partial conversion towards renewable hydrogen. 3.4-5.4 GW of offshore wind capacity is assumed to be installed and 4-4.5 GW of electrolyser capacity including both storylines with island and/or platform structures. The hydrogen is foreseen to be landed onshore via the NGT pipeline. The greenfield gas development contains the connection of the N5 platform to the Riffgat windfarm substation and the G17 platform connected to the Gemini wind park and results in a NPC of 603 M€ for production and 47 M€ for platform electrification. The total NPC to develop Hub East individually resulted in 13-20 B€. There is potential for electricity interconnections between this hub and Germany. No existing pipelines are available to provide potential interconnections for hydrogen between this hub and other countries.

Hub North

Hub North involved a common implementation of greenfield gas extraction, platform electrification, offshore wind production and partial conversion towards renewable hydrogen, and is located the furthest from shore compared to the other hubs. 19.5 GW of offshore wind capacity is assumed to be installed and 8 GW of electrolyser capacity, which is assumed to be located on platforms only because the water depth is too deep for sandy islands. In the Hub North storylines there is mainly focussed on how to connect this hub to shore by using new and/or existing pipelines, this analysis showed a total NPC of 4.4 4.8 B€ (reused NoGaT and NGT incl. new section(s), 27.6 GW). Standalone platform electrification resulted in an NPC of 224 M€. The total NPC to develop Hub North individually resulted in 34-35 B€. Due to its central location within the North Sea there is potential with electricity interconnections to all North Sea countries from this hub. Existing pipelines provide opportunities to make interconnections for hydrogen to Norway, Denmark and Germany from this hub. Due to its central location on the North Sea and the circumstance that large volumes of the hydrogen produced – in contradiction to the other two hubs) will not land via het NGT close to the potential onshore hydrogen storage location at Zuidwending, Hub North might be an offshore hub where the option of large-scale offshore hydrogen storage might be explored in the available salt structures or hydrocarbon reservoirs.

Integrated hubs

An integrated hub scenario is presented to show the interconnections between the three above-described offshore energy hubs. As the NGT pipeline is crossing both hub West and hub East, and is located suitable to be connected with a new pipeline to hub North as well, there might be a realistic chance that the hydrogen flows of the different offshore hubs will be connected. Moreover, this provides the opportunity that these pipelines can be used as an offshore extension of the national hydrogen network with short connections to neighbouring countries. Developing all three energy hubs would significantly contribute to a sustainable Dutch energy supply system.

All hubs overview

Table 7.1: Overview of main characteristics of each hub in storylines 2(b)

Hub Function	Characteristic	Hub West	Hub East	Hub North	Combined Hubs
Offshore wind	Installed capacity 2050 (GW)	8.7 GW	5.4 GW	19.5 GW	33.6 GW
	Max electricity production volume (TWh/a)	43 TWh/a	39 TWh/a	99 TWh/a	181 TWh/a
	NPC offshore wind (B€)	11 B€	10 B€	16 B€	38 B€
	NPC cables (B€)	1.8 B€	1.2 B€	5.3 B€	8.2 B€
Renewable hydrogen	Installed capacity 2050 (GW)	5 GW	4.5 GW	8 GW	18 GW
	Max hydrogen production volume (Mt/a)	0.48 Mt/a	0.28 Mt/a	0.43 Mt/a	1.2 Mt/a
	NPC hydrogen production (B€)	4.8 B€	6.0 B€	7.1 B€	18 B€
	NPC hydrogen pipelines (B€)	1.6 B€	1.3 B€	4.4 B€	7.3 B€
Natural gas	Max natural gas production (bcm/a)	-	2.0 bcm/a	5.4 bcm/a	7.4 bcm/a
	NPC natural gas production (B€)	-	0.8 B€	0.9 B€	1.7 B€
	NPC platform electrification (M€)	272 M€	47 M€	224 M€	544 M€
CO2 storage	Max CO2 stored (Mt/a)	27 Mt/a	-	-	27 Mt/a
	NPC CO2 storage network (B€)	0.5 B€	-	-	0.5 B€
Total NPC (B€)		**15 - 22 B€**	**13 - 20 B€**	**34 - 35 B€**	**62 - 75 B€**

7.1 The offshore energy hub perspective and its value

The described and modelled offshore energy hubs provide a concrete vision of what the required infrastructure could look like if system integration is performed in the Dutch part of the North Sea. The defined locations of the hubs are investigated as potential locations for system integration on the North Sea. Therefore, these hubs are suitable locations to develop the initial pilots which are required to move towards the implementation of offshore system integration. The described storylines could be used as a first attempt to develop an integrated vision for the North Sea. Besides, the storylines provide insights into what investments are required to realise infrastructure for offshore energy hubs, involving new designs for offshore P2G platforms and islands. The designs of the hubs should not be considered as the 'single best solution', but as a realistic starting point for further development and realisation of an integrated offshore energy system.

In the techno-economic NSE 2 it was already concluded that the “value of system integration lies in financial and economic benefits for multiple stakeholders and collaboration is key to capture all value” (60). System integration could provide new opportunities for existing infrastructure and create value for societal beneficial investments that otherwise would be harmed by lock-in effects. Likewise, as in earlier phases it was concluded that we should not separate the views on the natural gas, electricity and hydrogen systems in silos, also the defined offshore energy hubs should not be seen in isolation. The hubs have the potential value of being central connection points where multiple commodities come together. In this study the potential of developing interconnections (of electricity, hydrogen and carbon dioxide) from the hubs to neighbouring countries have been shown and the degree to which hydrogen pipelines can be connected to an offshore network linking the three hubs with each other.

Currently, offshore hydrogen storage is not taking place in the storylines developed in this study. If this is the case in a specific hub, it could be expected that other hubs could benefit from this storage as well. It is essential to align the design and capacities of production and transport infrastructure located in the hubs within the total energy system of the North Sea region. First insights in how our interconnected hub storyline would behave in a future energy system are provided in WP6 of this North Sea Energy program.

7.2 Offshore energy hub challenges

The development of the designed offshore energy hubs will not occur by itself. System integration requires involvement of multiple sectors and therefore multiple types of stakeholders, which deserves coordination and a lot of hurdles that should be taken. Three main challenges that are foreseen in the development of offshore energy hubs are concluded.

The first challenge is to overcome the interdependencies between the involved actors. To illustrate this, some examples of dependencies that are given. In Hub East and Hub North, greenfield gas production is strongly interlinked with the P2G activities through the utilization of the gas produced. In Hub West, dependencies exist between the electrification required for P2G activities and the resulting electrification for CCS activities. Moreover, if pipelines can be re-used for both hydrogen and carbon dioxide transport, a proper decision should be made what is of most value.

A second challenge is to align decision making between the involved actors. With regards to the designed offshore energy hubs a lot of activities and investments are involved which are expected to involve a lot of different parties. Those parties are completely dependent on each other in developing these complete value chains. Moreover, large uncertainties and risks are faced such as policy and legal risks, technological risks and market risks. The individual investment decisions that involved parties might be willing to make, depend on these risks, but moreover on investment decisions of other parties, which causes a so-called supply chain risk. A major challenge is how to find the right way of collaboration in these investment decisions, to what degree public institutions should perform certain activities (e.g. offshore network operation) and how the framework should look like that governs the group of stakeholders involved.

Lastly, a third challenge being worth mentioning is the landfall of offshore energy. In this study, the landfall of the energy was considered just to a limited extent. However, during the indicative investigation that was done in collaboration with the harbours, it was seen that the spatial issue of integrating the offshore energy to the mainland is a serious challenge. Serious amounts of offshore energy means that serious amounts of energy should be landed in the harbours, while actually this space is relatively scarce. This topic therefore deserves more attention than it has up till now and should become a vital part of the discussion how an integrated offshore energy system should look like.

8 References

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