WHEN TRUST MATTERS

SCREENING OF POSSIBLE HUB CONCEPTS TO INTEGRATE OFFSHORE WIND CAPACITY IN THE NORTH SEA

Danish Energy Agency

REPORT

CONTENTS

EXECUTIVE SUMMARY

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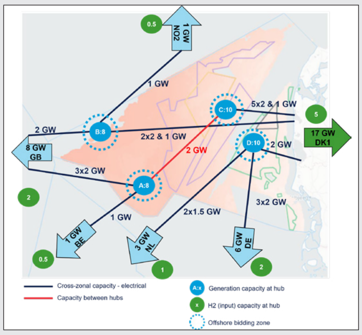
Danish Energy Agency (DEA) has commissioned DNV to conduct a study on the 'Screening of possible hub concepts to integrate offshore wind capacity in the North Sea'. The objective of this investigation is to compare a Hub&Spoke offshore infrastructure approach with alternative ways to integrate large quantities of offshore wind from the Danish Exclusive Economic Zone (EEZ) into the onshore systems of the North Sea countries in 2050.

DNV has delivered the study in two phases, first being a workshop-based scoping exercise aimed at identifying the most realistic yet different infrastructure concepts, and second being an assessment of those concepts against a number of Key Performance Indicators (KPIs). As a result, DNV has highlighted the relative merits of different infrastructure concepts and provided a holistic overview to DEA and its stakeholders.

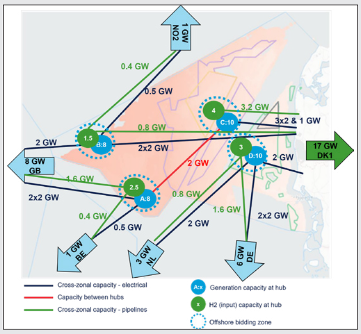
Four concepts have been proposed which vary in the level of offshore network concentration, location of hydrogen production and connectivity between power and hydrogen systems on the offshore hubs.

CONCEPT 1
Centralised - Hydrogen Onshore



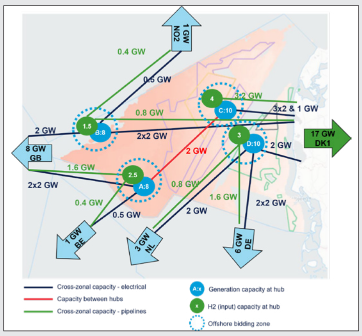
Centralized – Hydrogen Onshore concept, characterised by four hubs of approximately 10 GW spread across the Danish EEZ with hydrogen production located onshore.

CONCEPT 2
Centralized - Hydrogen Offshore - Combined Electricity and Hydrogen



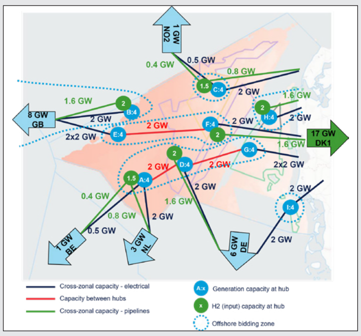
Centralized – Hydrogen Offshore – Combined Electricity and Hydrogen – similar to the previous concept, albeit with electrolysers located offshore and powered from offshore wind farms and wider power grid. The energy produced by all the windfarms can be delivered to shore both in the form of electrons or hydrogen molecules.

CONCEPT 3
Centralized - Hydrogen Offshore - Dedicated OWF's for hydrogen production



Centralized – Hydrogen Offshore – Dedicated OWF's for hydrogen production – similar to concept 2, although the hydrogen production is now disconnected from the wider power system offshore. For each of the offshore hubs, a certain proportion of the wind farms are only connected to electrolysers, hence all energy generated by these wind farms is converted to hydrogen offshore and delivered to shore as hydrogen molecules.

CONCEPT 4
Distributed - Hydrogen Offshore - Combined Electricity and Hydrogen



Distributed – Hydrogen Offshore – Combined Electricity and Hydrogen – similar to concept 2, although with nine hubs of 4 GW each spread across the Danish EEZ.

Characteristics	Concept 1	Concept 2	Concept 3	Concept 4
Capacity	Same assumptions on capacity allocation for power (table 2-3) and hydrogen (table 2-4) are applied to all concepts for a fair comparison			
Number and size of hubs	2 hubs of 10 GW each 2 hubs of 8 GW each			9 hubs of 4 GW each
Hubs support structure	Steel platforms (for water depth above 30 m Artificial sand island (relatively shallow waters)			Steel platforms (high water depth) Caisson islands (relatively shallow waters)
Evacuation of energy produced in the hubs	HVDC cables	HVDC cables Pipelines	HVDC cables Pipelines	HVDC cables Pipelines
Electrolysers location	Onshore	Offshore	Offshore	Offshore
Electrolyser powered by	Wider onshore network	Offshore wind farms (hubs) & energy from the wider grid	Dedicated offshore wind farms only (within the hubs)	Offshore wind farms (hubs) & energy from the wider grid

Whilst our investigation did not aim to indicate an absolute winner among the analyzed concepts, it did highlight a number of observations with regard to the relative performance of these concepts against each of the considered KPIs.

Key findings

DNV concludes that there is not one single concept that outperforms the others in every single considered KPI. Both Distributed and Centralised concepts have advantages. Distributed Concept brings higher flexibility as it allows to locate hubs more optimally with respect to the offshore wind lease areas and points of onshore connection and takes advantage of this location to minimise the cost. Though, it highly depends on the parks not being taken earlier. On the other hand, the Centralised Concepts take advantage of economies of scale by building artificial islands of 8-10 GW as some studies suggests that large scale islands can come at a significantly lower cost. The sensitivities exploring the impact of an optimised detailed design concepts and a more optimistic view on cost of offshore islands bring the cost difference between Decentralised and Centralised Concepts to negligible level considering the conceptual nature of this study. Onshore hydrogen production is likely to be more expensive than offshore, regardless of whether the offshore electrolysers are coupled to a wider power network or powered directly from dedicated individual windfarms. Whilst offshore electrolysers are expected to be more expensive than their onshore counterparts, the savings from avoiding the need to build some of the HVDC converters are of a much larger scale. For example, the difference between Concept 1 and 2 is around 6%. This conclusion holds even if the costs of the offshore electrolysis are by 20% more expensive than that of the onshore.

The concepts exhibit some minor differences in how the infrastructure is utilised. Namely, concepts with offshore hydrogen production have better overall utilisation, mainly as an outcome of lower curtailment levels. In moments when electricity price is low and there is oversupply in the system, it is possible to produce hydrogen offshore, thereby neglecting onshore constraints. Concept 1, with hydrogen production located onshore suffers from frequent curtailment caused by the inability of onshore system to absorb power and leads to the lowest asset utilisation. Note that we assume onshore electrolysers to be connected to the transmission grid, not behind-the-meter at the coast.

Centralised concept with offshore hydrogen generation from dedicated wind farm resulted in the lowest LCOE. Although, the differences with the combined electrical and gas connection in Centralised (Concept 2) and Distributed (Concept 4) hub setup are marginal. Meanwhile, the onshore hydrogen production in the Centralised concept led to a much higher LCOE. Hence, we conclude the location of hydrogen production to be a dominant factor, with hub size and number as well as connectivity of offshore electrolysers to have negligible effect on LCOE.

DNV has considered the technological maturity of the infrastructure concepts based on the present state-of-the-art power and gas transmission technology. Distributed concept may be more favourable as it features smaller components in relatively simple internal hub network topologies. Offshore hydrogen, currently considered to be immature, poses significant technical challenges.

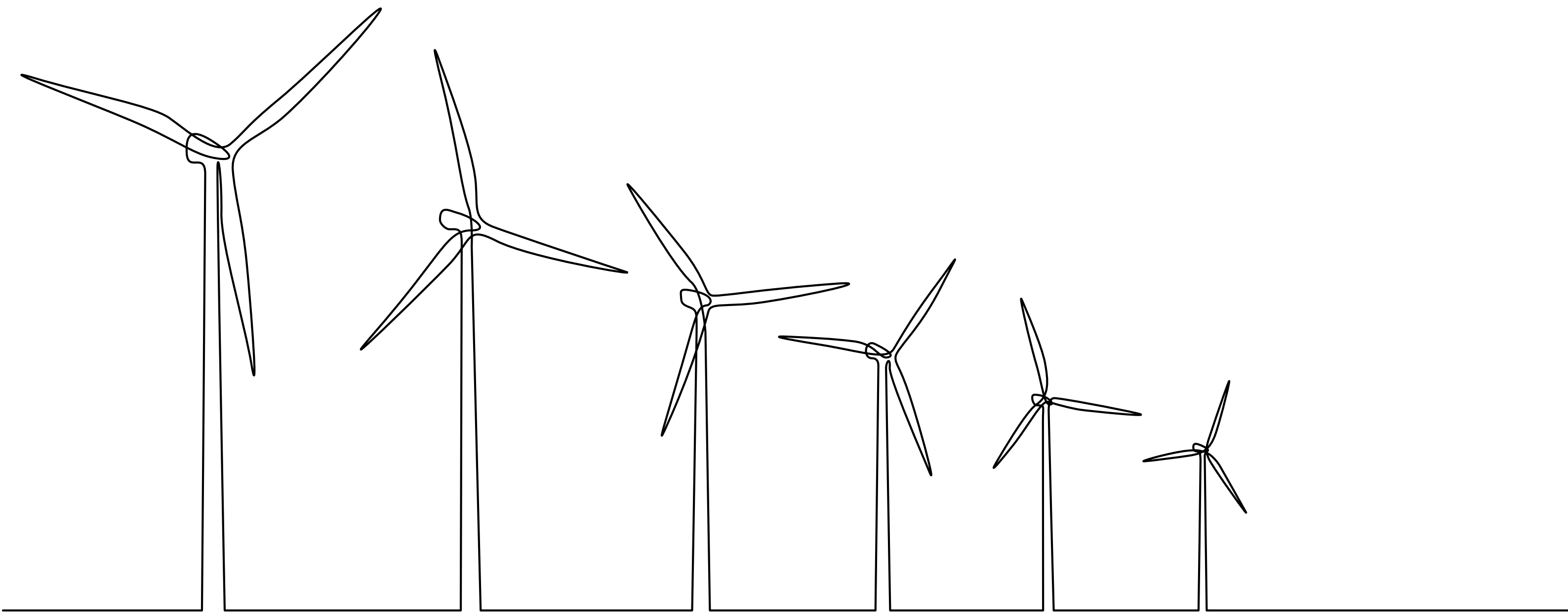
Our analysis has considered what impacts the different infrastructure concepts will have on the marine and coastal environment and social communities in the coastal areas. Distributed hub development allows for reducing the length of cables and pipelines by better optimising hub locations, which leads to reduced environmental impacts offshore. All concepts seem to lead to a similar number of onshore landing points, hence the magnitude of impacts on the communities in the coastal areas are barely affected by the choice of Distributed against Centralised, or Onshore against Offshore hydrogen production.

A distributed approach might be favourable as it allows to break down the entire infrastructure network into a number of smaller projects, which can be planned, designed and implemented in parallel with the deployment of offshore wind generation capacities. This, compared to the Centralised approach, minimises the necessity for the anticipatory investment and reduces the risk of stranded assets. Yet, Centralised concepts gain points on modularity since they have inherently more space for potential expansions in the future. Offshore hydrogen is likely to make modular expansion of offshore hubs more complicated due to the overall increase in the complexity of hub system design as an inherent feature of integrating electrical and hydrogen equipment.

We found that offshore hydrogen production leads to likely reductions in the requirements for onshore reinforcements needed to integrate the vast amount of offshore wind energy into the onshore system. By converting part of the generated energy to hydrogen offshore, the number of HVDC converters onshore, as well as the overhead lines onshore, can be reduced notably.

Finally, we have considered the regulatory complexity. In this context, Distributed approach to offshore hub development, based on the current state of legal and regulatory framework would face the least difficulties in the planning, development and operational phase. Smaller offshore hubs, featuring platforms rather than artificial islands, are currently better regulated. Obtaining permits, as well as financing and governance will be more straightforward for small offshore hubs. Concepts with Hydrogen offshore would be impeded by the uncertainty about the legal classification of hydrogen production at sea. Lack of clarity about ownership and governance for large scale offshore hydrogen production would be another barrier.

We note that both for the technology readiness level and regulatory complexity, DNV expects that the highlighted issues will be resolved in the coming years. Hence, our conclusions in these areas only concern the present state and indicate the need for development and progress in certain domains.



Study limitations

Our investigation is inherently conceptual in its nature – the objective was to compare the potential offshore infrastructure concepts in their 2050 state. These concepts should allow to integrate up to 36 GW of offshore wind in the Danish EEZ, the scale that is much higher than the current ambitions. This value is also significantly exceeding the expected demand for power in Denmark, thus inevitably large part of this capacity will have to connect to other North Sea countries.

Whilst limiting the scope of the study to a small number of dimensions allowed to reach certain insights about the outcomes of choices and compare the proposed concepts, the absolute values obtained within this study have little value. A number of practical assumptions were made with regard to the hub locations, their size and onshore points of connection. The network capacity was not optimised, which could allow to reduce costs and increase utilisation. DNV highlights that the focus of the study was on the comparative analysis, indicating relative performance of the considered concepts. The absolute costs, LCOE, utilisation rate and other KPIs should be treated as indicative only, as further changes will come out as a result of the detailed design phase of such projects.

Our concepts have not considered the emerging wind-to-hydrogen turbines, whereby small-scale electrolysers are located within the wind turbine.

One difference between the Centralised and Distributed concept that is not further quantified in our analysis but is worth to note is the impact on array cables. All Centralised concepts are heavily dependent on the utilisation of 132 kV HVAC array cables to enable direct connection of the windfarms to larger hubs. As such 132 kV HVAC cables are available and mature, although have not been used as inter-array cables. Distributed concept can be implemented with 66 kV array cables because hubs connect smaller generation capacity and can be located closer to the windfarms. Consideration of offshore arrays and all other equipment that is typically owned by wind farm developers is out of scope of this study.

Note that we deliberately exclude radial* concept from the consideration, since multiple studies have proven it to be sub-optimal for large quantities far offshore in the long term**.

This concept does not allow to achieve economies of scale and capitalise on the lower unit cost of HVDC equipment utilised for far offshore wind farms.

Our cost assessment did not consider the intertemporal development of the proposed concepts, but rather looked at the snapshot of their state in 2050.

The extent of power flow modelling was limited to capture the network utilisation but it did not include detailed dispatch analysis or power system constraints. This has limited the depth of our assessment, whereby only costs have been monetised, while socio-economic benefits were deliberately left out of scope.

Our technology choice was conservatively based on the 2022 state-of-the-art technology availability for the power equipment, on the one hand. On the other hand, for hydrogen our assumptions include technical feasibility of offshore production at GW scale, which has not been realised so far. A number of KPIs, such as environmental and social impacts, modularity, regulatory complexity and requirements for onshore reinforcement were valued qualitatively based on the DNV's expertise gained in similar studies.

* A radial connection is a point-to-point connection

** Studies such as PROMOTioN; the Offshore Coordination Project set up by the NGESO, and Study of the benefits of a meshed offshore grid in Northern Seas region by TE, ECOFYS and PwC for DG ENER, just to mention some

1. BACKGROUND AND OBJECTIVES

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1.1 General context

The Danish legislature has decided to construct an energy island in the North Sea. The idea behind the hub is to strengthen the integration of Europe's power grids and increase renewable electricity generation necessary for a climate-neutral Europe with the expectation of a massive deployment of offshore wind energy in the future. The plan envisages the establishment of an artificial island in the North Sea that will serve as a hub for offshore wind farms supplying 3 GW of energy, with a long-term expansion potential of 10 GW.

The Danish Energy Agency (DEA) is responsible for tasks linked to energy production, supply and consumption, as well as Danish efforts to reduce carbon emissions.
The Danish Energy Agency is playing a key role in leading the project that will transform the energy island from a vision to reality. The island is a pioneer project that will necessitate the deployment of existing knowledge into an entirely new context. DEA's goal is to find the best solutions to the aspects of the project that remain unsolved. Thus, the Danish Energy Agency is investigating possible infrastructure designs (concepts or regimes) to integrate and transport large quantities of offshore wind energy in the North Sea to shore in the long term, by 2050.

1.2 Objective of the study

The objective and application of this study is a robustness check of th The objective and application of this study is a robustness check of the energy island concept against other possible solutions of infrastructure in the future. Danish Energy Agency wants to expand its knowledge of the advantages and disadvantages of different concepts and appropriate pathways to integrate large quantities of wind energy into the Danish and other North Sea countries' energy systems. In addition, the attained knowledge and insights could also be included in the planning of the next phases of the energy island. The analysis should address issues related to the design, development, and deployment of Danish energy infrastructure within the Danish exclusive economic zone (EEZ) in the North Sea from a technical and economic perspective.

2. METHODOLOGY

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2.1 Overview

The goal of this study is to review potential solutions to evacuate and integrate offshore wind generation to shore from the Danish EEZ specifically, and wider North Sea region in the long term, i.e. 2050. The approach is therefore divided into two parts:

- Phase 1 – Workshops
- Phase 2 – Analysis

2.1.1 PHASE 1 - WORKSHOPS

Seeing the conceptual nature of this investigation, discussions around alternative configuration concepts to evacuate large quantities of (wind) energy to shore towards 2050 were performed in a workshop environment.
The workshops were used as the primary means of bringing together experience of the Danish Energy Agency team and DNV experts.
The workshops were divided into two steps, as shown in Figure 2-1.

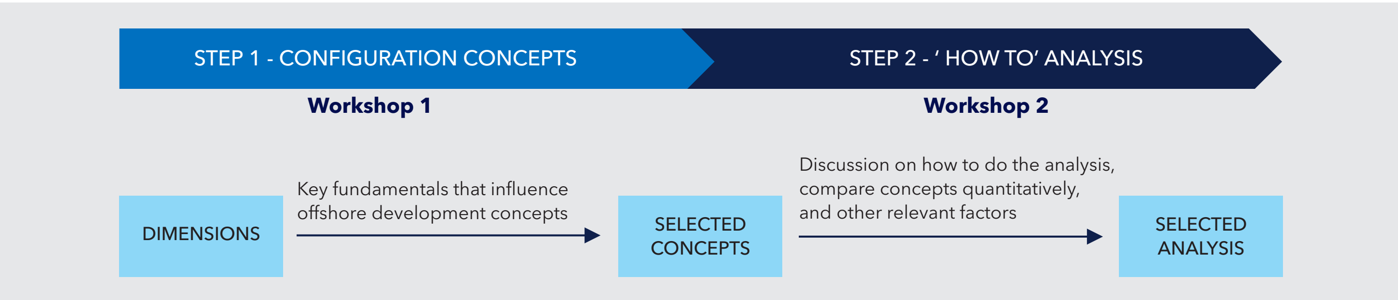


Figure 2-1 Workshop structure

The first workshop allowed us to jointly develop a foundation for a principal understanding of the dimensions that influence offshore development concepts. This workshop had a fundamental nature and aimed to pre-select a limited number of concepts for the further detailed analysis (Figure 2-2).

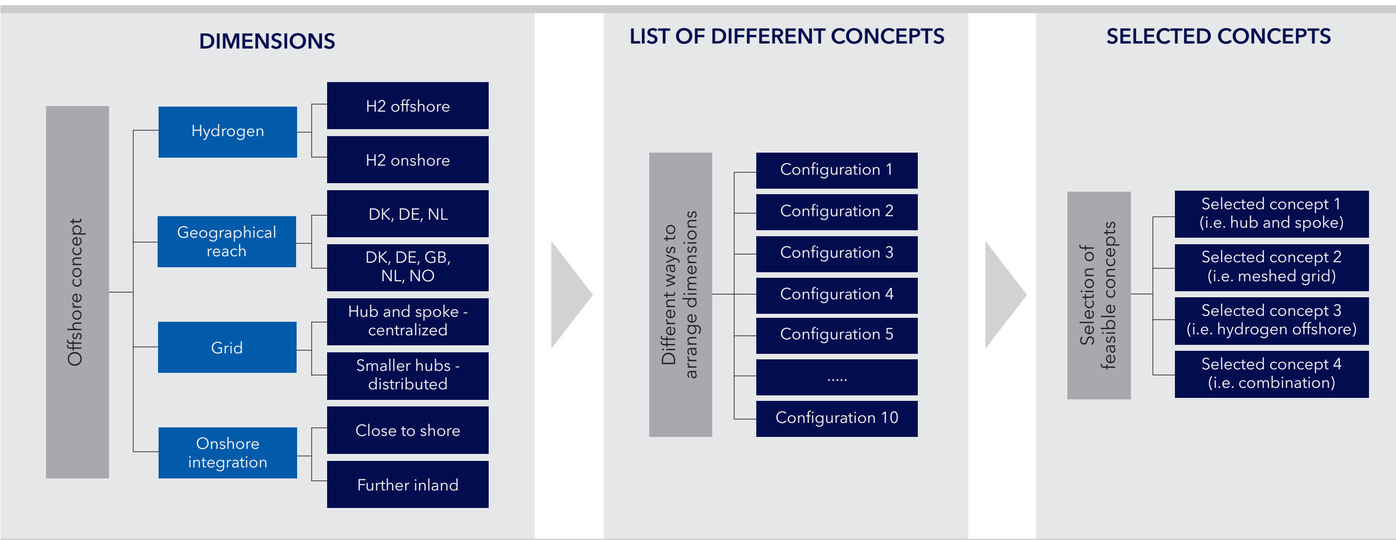


Figure 2-2 Workshop 1 - Configuration concepts

Within the second workshop, the focus was on identifying how to execute the analysis, including KPIs and how these could be evaluated quantitatively and qualitatively, and how to compare relevant other factors (Figure 2-3).

2.1.2 PHASE 2 - ANALYSIS

Having framed the assessment framework during the second workshop, DNV has executed the actual analysis for the pre-selected topologies. Because of the conceptual nature of the project and limited timeline, we have been pragmatic and have made assumptions where there were gaps or unknowns. The underlying assumptions and limitations of the analysis are indicated in section 4.2.

The outcomes of the analysis should allow DEA to:

1. Compare the pre-selected concepts in terms of their merits and drawbacks against the selected KPIs,
2. Identify barriers and opportunities
3. Evaluate the long-term suitability of the hub-and-spoke approach

In the remainder of this chapter, DNV focuses on the work that has been performed as a part of the Phase 1 Workshops, namely concept- and assessment framework definition. The outcomes of Phase 2 Analysis are reported in chapter 4.

Possible instruments to formalize decisions

Having identified the decision space, we will present instruments to guide the analysis. A CBA methodology for offshore grids that we developed within the PROMOTioN and further tailored in offshore coordination project for NGESO will be used.

As not all costs and benefits can be monetized, qualitative assessments will be combined with quantified and monetized metrics in a multi-criteria analysis.

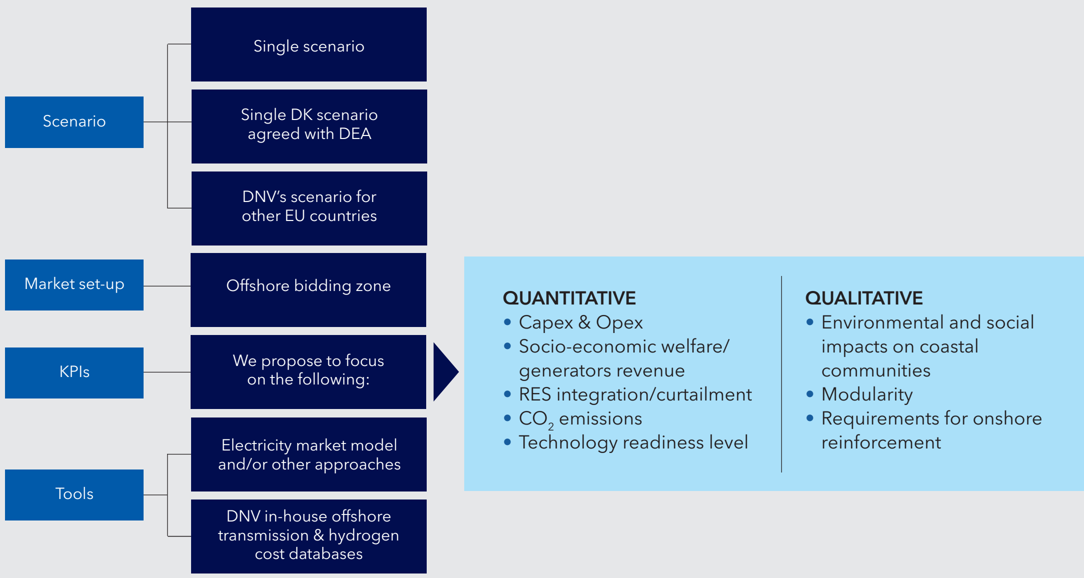


Figure 2-3 Workshop 3 - 'How to' analysis

2.2 Definition of concepts

2.2.1 DIMENSIONS

As described above, the objective of the first workshop was to identify a limited set of diverse and realistic offshore infrastructure concepts for the further analysis. In this context, DNV have introduced the following definition of what a concept is.

Concept – a high-level topology-like illustration of offshore infrastructure (electrical and gas) that shows how its primary functions (energy evacuation and trade) are realised. A concept constitutes a conceptual or functional design which:

- Reflects fundamental principles/philosophy of network design but is not the actual design itself.
- Does not show concrete technical solutions and implementation
- Does not reflect detailed real locations of offshore wind production and connection points
- Does not reflect a specific offshore wind installed capacity
- Does not reflect a concrete number of hubs or connections

Figure 2-4 below gives an example of how a concept could look at the North Sea level.

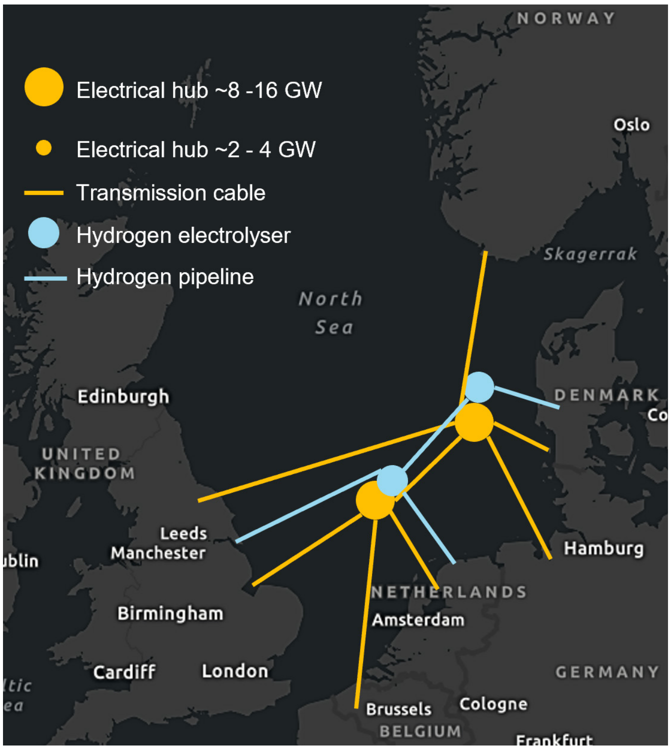


Figure 2-4 Example of a concept

A formal approach to concept definition was taken based on the so-called "dimensions" of concept comparison. These dimensions are meant to describe a certain characteristic of a concept and meet the following requirements:

- Decision makers can make a choice on how future concept might look across a dimension.
- Dimensions are independent from each other and can be combined with a limited number of exceptions.
- Two extreme options of how a concept can look are fined for each dimension.

Following the discussion with DEA, DNV limited the list of dimensions with corresponding extremes to the ones shown in Table 2-1. Note that we deliberately exclude radial* concept from the consideration, since multiple studies have proven it to be sub-optimal for large quantities far offshore in the long term**. This concept does not allow to achieve economies of scale and capitalise on the lower unit cost of HVDC equipment utilised for far offshore wind farms.

* A radial connection is a point-to-point connection
** Studies such as PROMOTioN; the Offshore Coordination Project set up by the NGESO, and Study of the benefits of a meshed offshore grid in Northern Seas region by TE, ECOFYS and PwC for DG ENER, just to mention some

DESCRIPTION/RATIONALE	EXTREME 1	EXTREME 2
	1. Network concentration	
Reflects the level of network concentration. Covers the most prominent grid topology types that are considered by the countries around the North Sea (NL, DK and DE – centralised, UK – distributed).	Centralised – a few large hubs across the North Sea with 3-4 hubs in Danish EEZ. Potentially artificial islands of 6-16 GW.	Distributed – many smaller hubs (around 2-4 GW each) across the North Sea with 6-10 hubs in Danish EEZ. Likely – steel platforms.
	2. Hydrogen location	
Hydrogen production is seen as the most promising option to facilitate sector coupling, decarbonise industries and reduce curtailment of RES. It is widely accepted that hydrogen will definitely emerge in/around the North Sea although the scale is not clear yet.	Onshore – production of hydrogen onshore	Offshore – production of hydrogen offshore by: a) Large electrolysers installed on offshore support structures b) Small electrolysers installed on wind turbines
	3. Dedicated OWF's for hydrogen production	
Future market dynamics and infrastructure cost might result in offshore wind farms connected only via gas pipelines to shore more attractive than alternative options involving transfer of power through electricity cables.	Combined hydrogen and electrical - possibility to evacuate the produced energy both as electrons and molecules.	Dedicated gas connection – all produced energy is directly converted to hydrogen and exported to shore through pipes.

Table 2-1 Dimensions

To facilitate the understanding of how each dimension affects the concept design in practice, Appendix A – Concept Dimensions Illustrations contains graphical representation of the two extremes for each of the dimensions.

Making a design choice across each of the dimensions will have its impacts, which allows to judge how different concepts compare to each other. The high-level summary of the impacts of a choice per dimension is summarised in following Table 2-2.

The three selected dimensions allow for 6 realistic concepts, with onshore hydrogen prohibiting for any choice related to the presence of dedicated hydrogen OWFs.

1. Centralised – Hydrogen onshore
2. Centralised – Hydrogen offshore – Combined Hydrogen and Electrical
3. Centralised – Hydrogen offshore – Dedicated gas connection
4. Distributed – Hydrogen offshore – Combined Hydrogen and Electrical
5. Distributed – Hydrogen onshore
6. Distributed – Hydrogen offshore – Dedicated gas connection

Out of these six concepts, the first four were selected for the further detailed analysis during the workshops.

DIMENSION	EXTREME 1	EXTREME 2
1. Network concentration	**Centralised** • High security impacts in case of failure • Potential for cost savings (support structures) • Simple network protection system • Potentially less environmental impact	**Distributed** • Better redundancy • Potential for cost savings (cables) • No anticipatory investment and low risk • High coordination efforts required
2. Hydrogen location	**Onshore** • Lower offshore asset utilisation • Easier control of OWFs • Fits under existing regulatory framework	**Offshore** • Requires changes in regulation (OWF incentives, operational codes, etc.) • Less mature concept • Potential for cost savings
3. Dedicated hydrogen OWFs	**Combined H2 and el.** • Lower utilisation of the electrolysers • More flexibility for OWF to choose where to market the generated energy (electricity or gas)	**Dedicated gas connection** • Less flexibility • Zero curtailment • No electrical infrastructure needed

Table 2-2 Impacts of choices across dimensions

2.2.2 APPROACH TO DETAILED DESIGNS

In order to be able to evaluate the KPIs, high-level designs are insufficient and needed to be further elaborated. This is particularly required to estimate the costs (CAPEX and OPEX) and to implement each concept in the market model which would allow to estimate some of the benefits (socio-economic welfare, RES integration, CO_2 emissions).

The objective of this stage is to produce detailed concept designs which will contain information about:
- Exact location of each hub
- Capacity of hubs (connected generation)
- Capacity of electrolysers on hubs
- Power and gas connections between hubs and from hubs to onshore systems
- Capacities of connections

DNV has developed the following process to create the designs meeting the above requirements:

1. **Define offshore generation installed capacity in Danish EEZ**
DNV and DEA agreed to use 36 GW as a capacity to be integrated via offshore infrastructure within this project.

2. **Define size of individual hubs**
DNV and DEA agreed to use ~10 GW for Centralised concepts and 4 GW for Distributed one.

3. **Define hub locations**
Based on the LCOE map, wind resource map* and maritime spatial plan** provided by DEA, DNV has selected 4 locations for the Centralised and 9 locations for the Distributed concept (see Figure 2-5).

4. **Define cross-zonal capacities and capacities to DK**
Based on the DNV scenario, as explained in section 2.3.2.2, DNV has defined the total capacity of offshore wind connected from Danish EEZ to the North Sea countries. This is summarised in Table 2-3.

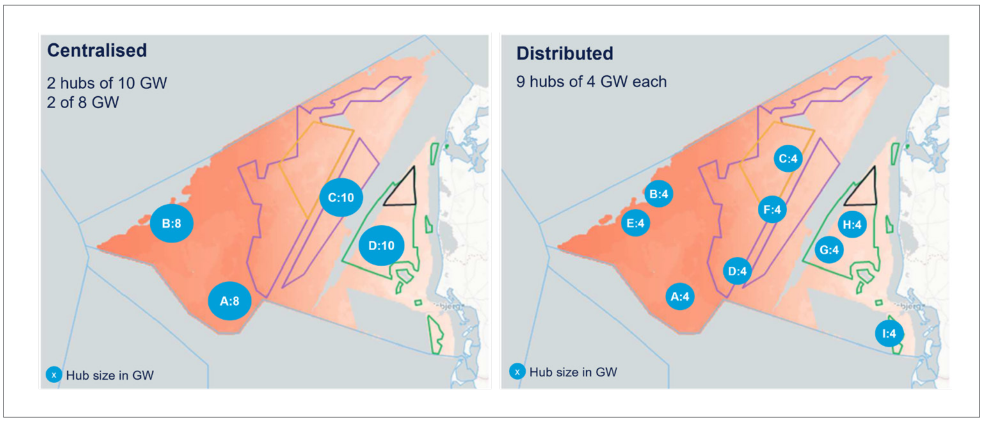


Figure 2-5 Selected hub locations and generation capacity

Countries	Total connected capacity	Installed capacity in DK EEZ	Connected capacity from DK EEZ (integrated)	Installed capacity in own EEZ (radial)
Belgium	6.0	1.0	1.0	5.0
Germany	48.4	5.5	6.0	42.9
Denmark	21.5	21.5	17.0	4.5
Great Britain	74.6	8.0	8.0	66.6
The Netherlands	34.4	3.0	3.0	31.4
Norway	12.7	1.0	1.0	11.7
TOTAL	**197.6**	**40.0**	**36.0**	**162.1**

Table 2-3 Connection capacities to onshore systems (GW)

* https://globalwindatlas.info/
** https://havplan.dk/en/page/info

5 **Connect hubs to the onshore systems (in accordance with Table 2-3)**
Based on the geographical proximity, select hubs which are most suitable (minimise costs of cables and environmental impacts) to be connected to a certain country to reach the total size of connection capacity.

6 **Define capacity between hubs**
As such there is a limited number of offshore grid functions that govern the decision on how to connect the hubs. These functions are:

- wind evacuation – export of generated offshore wind energy to shore. Offshore grid should allow to always evacuate all generated energy, without curtailment.
- trade between countries – offshore grids can facilitate trade between countries (serve as interconnectors) where this is economically justified.
- onshore grid reinforcement – offshore grid can support onshore grid by providing alternative transmission corridors, in parallel to the main onshore grid transmission path.
- redundancy of offshore grid – offshore grid may have increased level of redundancy, where failure of one or a few links does not lead to curtailment.

DNV and DEA recognised that not all generation capacity needs to be connected to Denmark, even though it is installed in Danish EEZ. As such each additional connection between hubs will significantly add to the total costs due to additional cables and protection equipment required to realise it. Therefore, we aimed at creating lean designs, which comply with the above rationale.

An important assumption that was made concerns the technology and rating of individual links. DNV assumed ±525 kV multi-terminal HVDC technology with capacity of up to 2 GW for electricity cables. 2 GW HVDC converters are used as standard blocks for the hubs. According to DNV, this reflects the state-of-the-art technology by 2030. We note that DC technology will mature, and higher voltages will be achieved in the next 15-30 years, by 2050. Utilisation of mixed voltage levels (±525 kV and above combined in one system) will potentially be possible if DC/DC transformers become industrialised. At present there is no insight of when and what the next voltage level will be, hence such a conservative assumption is made.

Finally, DNV assumed that the maximum loss of infeed (LoI) limit in DK1 bidding zone will be at least 1 GW, which allows to use 2 GW bipole with metallic return connections safely. The inherent feature of this type of DC connection is that in case one pole fails, i.e. 1 GW is lost, it is still possible to continue power transfer through the remaining healthy pole at a level of 1 GW, not violating the LoI limit*.

It is on this basis, that we can discard the "redundancy" function from the list. Seeing the magnitude of the capacity of connections to the onshore systems (Table 2-3), most of them will be implemented as several parallel links of 2 GW. Each hub will have multiple DC circuits connecting it to one of the onshore systems. This is an embedded redundancy, thus there is no need in providing additional redundancy by connecting the hubs between themselves. Next to that, we can also ignore the function of onshore grid reinforcement, since Danish grid, according to DEA, is not expected to have significant congestions that could be resolved via offshore corridors.

The remaining two functions that our designs should perform are energy evacuation and trade. All concepts are designed in a way to avoid potential curtailment due to the lack of export capacity, i.e. there is always enough electrical and/or gas transmission capacity to evacuate power from all offshore windfarms at any production level. The onshore scenarios are also the same for all four concepts. However, there will still be curtailment of the OWFs and differences in curtailment levels between the concepts. This is due to onshore conditions such as demand and generation patterns, but also offshore conditions related to geographic location and production profile of the OWFs, grid interconnection between hubs, as well as potential electricity demand from the offshore electrolysers. Curtailment will typically arise when there isn't sufficient grid capacity to balance out demand and generation within a bidding zone.

* See p.146 for further details https://www.promotion-offshore.net/fileadmin/PDFs/D12.4_-_Final_Deployment_Plan.pdf

7 **Incorporate hydrogen production and transmission**

In the last step, we add hydrogen infrastructure to the power system infrastructure. The location of electrolysers (onshore or offshore) is based on the concept definition. The rating of electrolysers is calculated following the rationale given in 2.3.2.2. Where certain offshore wind capacity is connected to electrolysers, we reduce the capacity of power cables and HVDC converters accordingly, not to over-size the total capacity of connection to shore (electrical and gas) beyond what is required to avoid curtailment and provide economically justified opportunity for trade.

Based on the DNV scenario, as explained in section 2.3.2.2, DNV have defined the total capacity of hydrogen connected from Danish EEZ to the North Sea countries. This is summarised in Table 2-4.

Countries	Connected capacity from DK EEZ (integrated)	Via power cable (GW)	Input to the electrolyser (electrical GW)	Delivered to onshore system (gas GW)
Belgium	1.0	0.5	0.5	0.4
Germany	6.0	4	2	1.6
Denmark	17.0	12	5	4.0
Great Britain	8.0	6	2	1.6
The Netherlands	3.0	2	1	0.8
Norway	1.0	9.5	0.5	0.4
TOTAL	**36.0**	**25**	**11**	**8.8**

Table 2-4 Hydrogen connection capacities to onshore systems (GW)

2.2.3 CONCEPT DESIGNS AND DESCRIPTION

The above approach allowed to develop the following offshore infrastructure designs. Note that in the following figures only developed designs are shown, i.e. we do not show transmission infrastructure that is part of the European power system regardless of the changes explored by this study. Several interconnectors are already implemented or are planned to be deployed in the North Sea in the coming years, those operational in 2050 are shown in Figure 2-6.

It is important to highlight that the same assumptions on capacity allocation for power and hydrogen are applied to all concepts for a fair comparison. While Table 2-5 shows general characteristics of the concepts, the following pages will describe them in more detail.

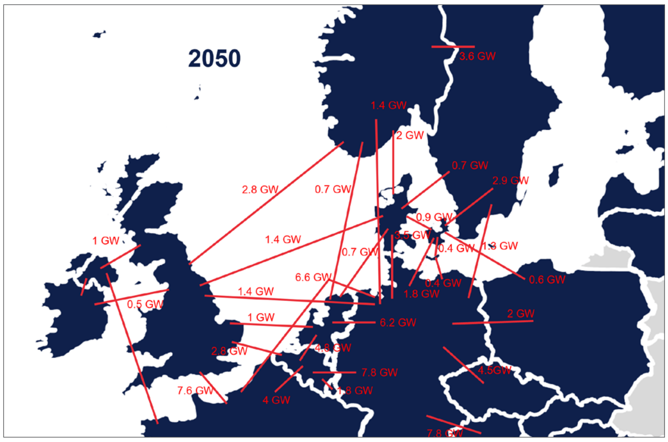


Figure 2-6 Existing and planned interconnectors between North Sea countries in 2050

Characteristics	Concept 1	Concept 2	Concept 3	Concept 4
Capacity	Same assumptions on capacity allocation for power (table 2-3) and hydrogen (table 2-4) are applied to all concepts for a fair comparison			
Number and size of hubs	2 hubs of 10 GW each 2 hubs of 8 GW each			9 hubs of 4 GW each
Hubs support structure	Steel platforms (for water depth above 30 m Artificial sand island (relatively shallow waters)			Steel platforms (high water depth) Caisson islands (relatively shallow waters)
Evacuation of energy produced in the hubs	HVDC cables	HVDC cables Pipelines	HVDC cables Pipelines	HVDC cables Pipelines
Electrolysers location	Onshore	Offshore	Offshore	Offshore
Electrolyser powered by	Wider onshore network	Offshore wind farms (hubs) & energy from the wider grid	Dedicated offshore wind farms only (within the hubs)	Offshore wind farms (hubs) & energy from the wider grid

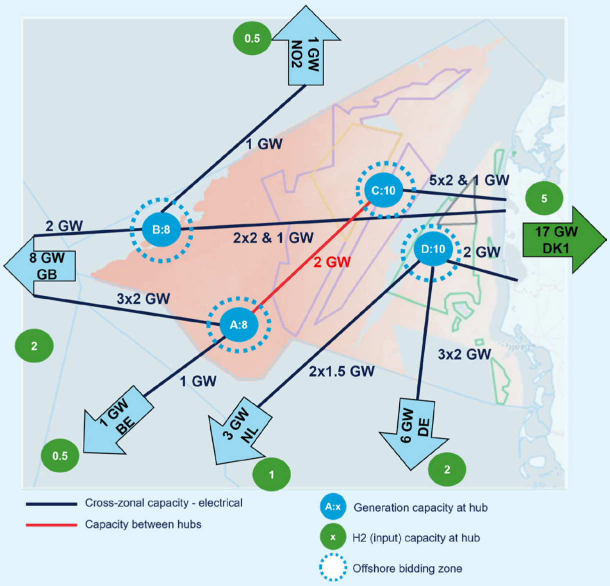
Table 2-5 General concept characteristics

2.2.3.1 Concept 1: Centralised hubs - Electric Offshore Topology with Onshore Electrolysers

Figure 2-7 is a graphic representation of the offshore infrastructure topology for Centralised Hubs – Electric Offshore Topology with Hydrogen Onshore Electrolysers concept in 2050. As with the other Centralised concepts, to be shown further, each hub constitutes a separate offshore bidding zone. There are four hubs in total. DNV assumes that hubs C and D can be implemented as artificial sand islands due to limited water depth, while hubs A and B will have to be implemented as a group of steel platforms since the water depth is above 30 m, a range that is not suitable for sand or caisson islands. The same assumption is applied across all Centralised concepts.

Concept 1: Centralised – Hydrogen onshore is characterised by a small number of large hubs spread across the Danish EEZ. All energy produced by the windfarms connected to each hub is exported to shore via HVDC cables. There are electrolysers installed onshore which receives power from the wider onshore network, thus not only from the offshore windfarms. Additional HVAC transformer stations must be installed onshore to bring the voltage down from the transmission level to ca. 3 kV which can be used by electrolysers.

Because of the selected hub size, of 8-10 GW, DNV assumed that artificial islands are used as a primary support structure type. Each hub hosts HVDC converters and DC switchgear required to collect the power from the connected OWFs and export it to shore. HVDC converters are interconnected such that power can be routed between different export circuits. Detailed information on connection length and line capacity for all concepts is given in Appendix C – Detailed Concepts.



Characteristics	Concept 1
Number and size of hubs	2 hubs of 10 GW each 2 hubs of 8 GW each
Total cable length (km) per capacity level	Cable 2 GW > 3388 Cable 1.5 GW > 596 Cable 1 GW > 1124 Cable 0.5 GW > 0
Total pipeline length (km) per capacity level	Pipeline 0.4 GW > 0 Pipeline 0.8 GW > 0 Pipeline 1.6 GW > 0 Pipeline 3.2 GW > 0
Electrolysers location	Onshore
Electrolyser powered by	Wider onshore network

Figure 2-7 Detailed 'Centralised - Hydrogen onshore' concept

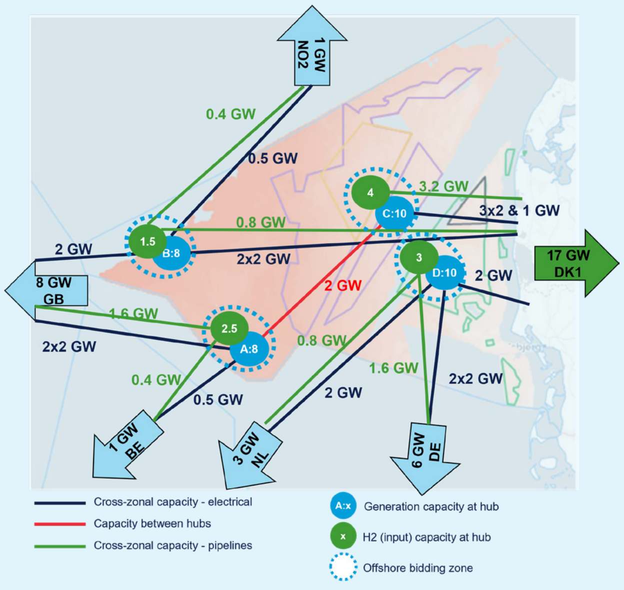
2.2.3.2 Concept 2: Centralised Hubs - Combined Hydrogen and Electrical Topology with Offshore Electrolysers

Figure 2-8 represents the detailed topology for Concept 2: Centralised Hubs – Combined Hydrogen and Electrical Topology with Offshore Electrolysers. In this concept, offshore electrolysers are located on the offshore hubs. Note that the figure shows the input (electrical GW) capacity of the electrolysers, while indicating transport (hydrogen GW) capacity of the pipelines. DNV assumes electrolysers to be based on PEM technology with electricity-to-hydrogen efficiency equal to 80%*.

This Concept 2 features the same hubs as Concept 1, however in this case hydrogen production takes place offshore. This means that all necessary equipment such as desalination plants, rectifiers, electrolysis modules, is located on the hubs. Electrolysers are powered directly from the offshore wind farms. Offshore wind farm array cables feed into an HVAC step-down transformer, which reduces array voltage to ca. 3 kV, which is later rectified into DC to be used for electrolysis. HVAC gas insulated switchgear (GIS) allows to choose between evacuating power via electrical cables or using it to produce hydrogen on the hub. Therefore, full generation capacity of each hub is connected to the electrical and gas grid. In addition, offshore electrolysers can in principle draw energy from the grid when it is cheap.

* https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf p.65

The design is developed without over-dimensioning the export infrastructure, i.e. the total capacity of power cables and hydrogen pipelines connecting a hub to other parts of the network is equal to the total generation capacity connected to the hub. In this way, as explained in section 2.2.2, there is no curtailment due to the lack of export capacity and at the same time the infrastructure costs are minimised. There are significantly less HVDC converters, both onshore and offshore, than in the previous concept. The number of converters can be reduced by a factor approximately equal to the total hydrogen generation capacity (2 GW assumed to be a standard converter size for each export link, offshore and offshore). The total capacity of the wind farms connected to electrolysers only is equal to 11 GW, in line with Table 2-4.



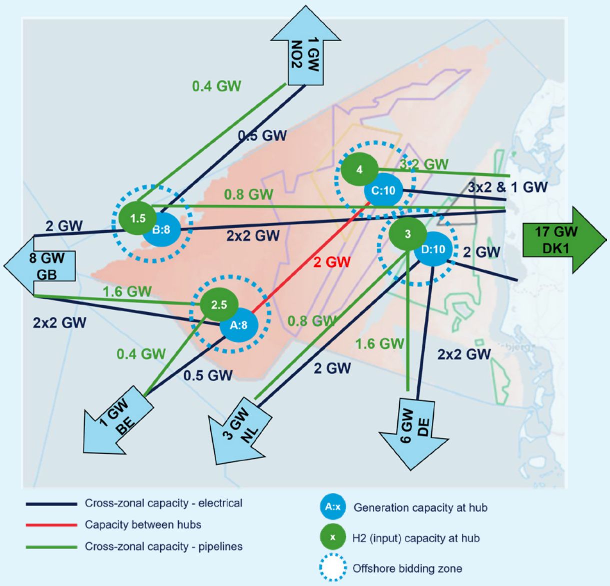
Characteristics	Concept 2
Number and size of hubs	2 hubs of 10 GW each 2 hubs of 8 GW each
Total cable length (km) per capacity level	Cable 2 GW > 2877 Cable 1.5 GW > 0 Cable 1 GW > 0 Cable 0.5 GW > 813
Total pipeline length (km) per capacity level	Pipeline 0.4 GW > 813 Pipeline 0.8 GW > 533 Pipeline 1.6 GW > 657 Pipeline 3.2 GW > 76
Electrolysers location	Offshore
Electrolyser powered by	Offshore wind farms (hubs), and energy from the wider grid

Figure 2-8 Detailed 'Centralised - Hydrogen offshore - Combined Hydrogen and Electrical' concept

2.2.3.3 Concept 3: Centralised Hubs - Combined Hydrogen and Electrical Topology - Electricity generation reserved for electrolysers

In this concept, the same topology as in Concept 2 is used and as shown in Figure 2-9. In previous Concept 2 the electrolysers are powered from the wind farms which are connected both to the electrical and hydrogen infrastructure. As explained before, electrolysers can draw electricity from the grid, and all windfarms can export their energy either via cables or via pipes, if the production level allows. This gives operational flexibility on how to deliver produced energy to shore.

In this Concept 3: Centralised – Hydrogen offshore – Dedicated OWF's for hydrogen production, the electrolysers are disconnected from the large offshore transmission grid and are powered only by some dedicated wind farms. This also means that these windfarms are not connected to the offshore electricity transmission grid, hence 100% of their electricity generation is converted to hydrogen and exported to shore via pipelines. Note that the OWFs connected to the electrolysers don't make up the entire generation capacity in the concept. Some of the OWFs are connected to the grid in the same way as in Concept 1. This gives less operational flexibility but allows certain cost savings on electrical equipment, such as HVAC GIS.
A high-level single-line diagram is given in Figure A 1 found in Appendix A. As in the previous Concept, the total capacity of the wind farms connected to electrolysers only is equal to 11 GW, in line with Table 2-4.



Characteristics	Concept 3
Number and size of hubs	2 hubs of 10 GW each 2 hubs of 8 GW each
Total cable length (km) per capacity level	Cable 2 GW > 2877 Cable 1.5 GW > 0 Cable 1 GW > 0 Cable 0.5 GW > 813
Total pipeline length (km) per capacity level	Pipeline 0.4 GW > 813 Pipeline 0.8 GW > 533 Pipeline 1.6 GW > 657 Pipeline 3.2 GW > 76
Electrolysers location	Offshore
Electrolyser powered by	Dedicated offshore wind farms (within the hubs)

Figure 2-9 Detailed 'Centralised Hubs - Combined Hydrogen and Electrical Topology - Electrical generation reserved for electrolysers' concept

2.2.3.4 Concept 4: Distributed Hubs - Combined Hydrogen and Electrical Topology with Offshore Electrolysers

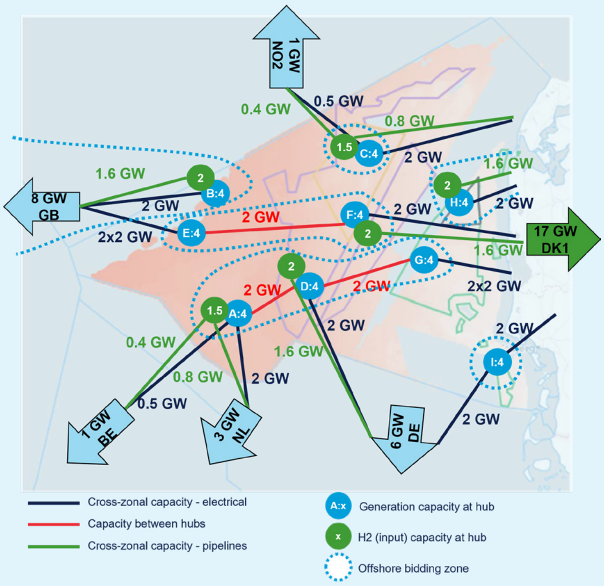
Concept 4: Distributed Hubs – Combined Hydrogen and Electrical Topology with Offshore Electrolysers is similar to Concept 2 in what concerns hydrogen production. The primary difference is in the number of hubs and their size. This concept features nine hubs, each with 4 GW of offshore wind generation capacity connected to them. Seeing the size of the hubs, DNV expects steel platforms or caisson islands to be used as a primary type of the support structure for such hubs due to the limited size. Hubs A, B and E are implemented as two times 2 GW steel platforms due to the high-water depth, while the rest of the hubs are implemented as caisson islands due to relatively shallow waters in those locations. Offshore electrolysers and other equipment required for the production of hydrogen can be placed on steel platforms similar to how it is installed on artificial islands.

The location of hubs in Distributed Concept is driven by the maximum wind resource availability per wind lease area. In particular hub I has been moved to the southeast part of Danish EEZ, assuming that the near shore parks will not be developed in that area in the near future. If near term parks are not available for the hub structure considered within this study because they have been connected to shore radially earlier, then the distributed hubs would have to be placed further offshore and would be more expensive. If they are available, then Distributed concept would allow to place smaller hubs closer to shore and to take advantage of this location to minimise the cost.

In order to make the comparison with the other concepts as fair as possible, we preserve the total capacity of electrical and hydrogen infrastructure connected to each of the countries, as well as connections between hubs enabling trade.

Because some of the hubs are only radially connected to one country, they become part of the national bidding zone. Other hubs have been aggregated into offshore bidding zones where there is sufficient transmission capacity between them, not to create bottlenecks for power transfers within a zone. As a result, four offshore bidding zones emerged, covering 24 out of 36 GW of installed offshore generation capacity. Table 2-6 highlights the similarities and differences previously described between the concepts.

From the detailed concept representations it can be seen that the capacity installed in Danish waters is mostly distributed between Denmark and UK, following their local demand and generation mix, which drives the dominance of East-West transmission corridors in our designs. In reality a detailed interconnector optimisation study would be required to identify whether East-West or e.g. North-South transmission corridors would lead to the highest socio-economic welfare. One can argue that East-West corridors facilitate trade between Great Britain and Denmark when wind speed varies between two countries. On the other hand, North-South corridor would enable trade between Nordics and Central Western Europe region. High wind next to the Netherlands, Belgium and Germany could replace Nordic hydro power resulting in South-North flow, effectively storing the electricity for periods with low wind, so the flow then can reverse to North-South direction. In the context of this discussion DNV do not expect any difference between Centralised and Distributed concepts.



Characteristics	Concept 4
Number and size of hubs	9 hubs of 4 GW each
Total cable length (km) per capacity level	Cable 2 GW > 2542 Cable 1.5 GW > 0 Cable 1 GW > 0 Cable 0.5 GW > 795
Total pipeline length (km) per capacity level	Pipeline 0.4 GW > 795 Pipeline 0.8 GW > 332 Pipeline 1.6 GW > 804 Pipeline 3.2 GW > 0
Electrolysers location	Offshore
Electrolyser powered by	Offshore wind farms (hubs), and energy from the wider grid

Figure 2-10 Detailed 'Distributed - Hydrogen offshore - Combined Hydrogen and Electrical' concept

Characteristics	Concept 1	Concept 2	Concept 3	Concept 4
Capacity	Same assumptions on capacity allocation for power (table 2-3) and hydrogen (table 2-4) are applied to all concepts for a fair comparison			
Number and size of hubs	2 hubs of 10 GW each 2 hubs of 8 GW each			9 hubs of 4 GW each
Hubs support structure	Steel platforms (hubs A and B) Artificial sand island (hubs C and D)			Steel platforms (hubs A, B and E) Caisson islands (all other 6 hubs)
How is the energy produced in the hubs transported?	HVDC cables	HVDC cables Pipelines	HVDC cables Pipelines	HVDC cables Pipelines
Total cable length (km) per capacity level	Cable 2 GW > 3388 Cable 1.5 GW > 596 Cable 1 GW > 1124 Cable 0.5 GW > 0	Cable 2 GW > 2877 Cable 1.5 GW > 0 Cable 1 GW > 0 Cable 0.5 GW > 813	Cable 2 GW > 2877 Cable 1.5 GW > 0 Cable 1 GW > 0 Cable 0.5 GW > 813	Cable 2 GW > 2542 Cable 1.5 GW > 0 Cable 1 GW > 0 Cable 0.5 GW > 795
Total pipeline length (km) per capacity level	Pipeline 0.4 GW > 0 Pipeline 0.8 GW > 0 Pipeline 1.6 GW > 0 Pipeline 3.2 GW > 0	Pipeline 0.4 GW > 813 Pipeline 0.8 GW > 533 Pipeline 1.6 GW > 657 Pipeline 3.2 GW > 76	Pipeline 0.4 GW > 813 Pipeline 0.8 GW > 533 Pipeline 1.6 GW > 657 Pipeline 3.2 GW > 76	Pipeline 0.4 GW > 795 Pipeline 0.8 GW > 332 Pipeline 1.6 GW > 804 Pipeline 3.2 GW > 0
Electrolysers location	Onshore	Offshore	Offshore	Offshore
Electrolyer type and efficiency	PEM 80%	PEM 80%	PEM 80%	PEM 80%
Electrolyser powered by	Wider onshore network	Offshore wind farms (hubs), and energy from the wider grid	Dedicated offshore wind farms (within the hubs)	Offshore wind farms (hubs, and energyh from the wider grid

*Table 2-6 Similarities and differences between concepts **

* The hub placements and cable lengths have not been optimised. This limits comparability between concepts, especially comparing Concept 4 to other concepts.

2.3 Assessment framework

2.3.1 BACKGROUND

The second aspect of the investigation of the different offshore infrastructure concepts is the assessment framework that governs the analysis. Such a framework allows to formalise the process, ensure consistency of comparison across the concepts and makes the assumptions traceable and transparent.

As a starting point, we take the CBA framework for offshore grids that DNV has developed within the EU research PROMOTioN project* and further refined in the Offshore Coordination project in the UK**. This framework builds on ENTSO-E CBA guideline 2.0*** but is tailored to large offshore grids, rather than specific projects. Within this study we will use a simplified version of the framework considering the high-level nature of the exercise.

The general structure of an assessment framework is defined in this report through six 'dimensions', as indicated in Figure 2-11.

Figure 2-11 Assessment framework

Scope

The first dimension of the methodology involves defining the purpose and scope of analysis and the projects that are assessed. The methodology can be used to assess the costs and revenues of a project (project assessment) or to assess the value to society of a project (societal assessment). Additionally, the purpose of the assessment should be clarified: what would qualify as "the best" alternative? What common purpose(s) should each project alternative fullfil? For example, alternative offshore grid topologies could have a common purpose to evacuate offshore wind energy. The scope of the project should also be defined to understand how project alternatives should be developed in dimension III of the methodology. A project could namely be a single project or a complex multi-purpose system.

Scenarios of market development

The second dimension of the methodology involves defining guidelines regarding the number, scope and setup of the scenarios under which to assess the costs and benefits of each project alternative. The guidelines provide an agreement on how system development scenarios should be set. Scenarios represent important future uncertainties including renewable energy capacity, generation portfolio, load growth, energy prices, CO_2-prices, regulatory framework, etc. For each scenario, the methodology defines the required set of parameters. These parameters will then need to be specified in the execution phase. The selected scenarios represent a set of future visions for the development of the onshore and offshore system in which project alternatives will operate. Alternatives may have different costs and benefits depending on the scenario under which they are evaluated. The project alternatives under consideration thus need to be assessed under multiple scenarios to avoid any bias and to ensure robustness of the result of the assessment under uncertainty. Clear and transparent guidelines on how to select and determine scenarios, and how to ensure an appropriate range of scenarios are therefore paramount to mitigate bias towards a certain alternative and facilitate a valuable comparison between project alternatives. Potentially, guidelines regarding sensitivity analyses within scenarios and dealing with uncertainty could be provided.

Project alternatives

The third dimension of the methodology defines the number of project alternatives that need to be assessed and how project alternatives should be developed. This allows the study to compare alternative strategic or technical solutions for the proposed infrastructure. Each project alternative requires a definition and information on the assets' functionality and characteristics. This includes guidelines on (i) the purpose(s) or function(s) of the project, and thus of each project alternative, (ii) the scope of variation between project alternatives, and (iii) the scope of services and technologies that could/should be included in scope of project alternatives. Additionally, guidelines should be provided on how to define the reference project or "null-alternative" that will serve as the point of comparison. Along with guidelines regarding the scope of project alternatives, guidelines should be provided regarding the project boundaries; what defines "a project"? which assets can be combined/clustered? where does the project begin and end both in physical terms and in time?

* https://www.promotion-offshore.net/fileadmin/PDFs/Deliverable_7.11_-_CBA_methodology_for_offshore_grids_-_final_-_DNVGL20180817.pdf
** https://www.nationalgrideso.com/document/182936/download
*** https://eepublicdownloads.entsoe.eu/clean-documents/tyndp-documents/Cost%20Benefit%20Analysis/2018-10-11-tyndp-cba-20.pdf

KPI Definition/identification
The fourth dimension of the methodology defines the different key performance indicators (KPIs) to assess for each project alternative. Each KPI will be valued (calculation or valuation method) through qualification, quantification or monetisation. This choice will affect the assessment framework. The KPIs will be set through understanding the cost and benefit impacts of the researched project alternatives. These impacts will be based on the different assets that make up each project alternative and the functionality and purpose of each project alternative. Furthermore, unintended consequences, i.e. likely beneficial or adverse effects should be considered in the analysis.

Tools
The fifth dimension of the methodology consists of defining the tools with which the different KPIs will be determined. Guidelines should be provided regarding the type of models and calculation tools required and how to set up and develop models. These models could, for example, be network or market models for projects in the energy sector. The methodology should clarify critical assumptions and implementation approaches to ensure all project alternatives will be evaluated under the same conditions.

Assessment
After the definition of the KPIs, the sixth dimension of the methodology will define the assessment approach. The assessment approach will depend on, and also define, the level of monetisation of the KPIs. The following must also be defined: the evaluation period of each project alternative and the method to evaluate costs and benefits over time. The assessment could include a financial analysis (NPV calculation), an economic analysis (monetization), a project scoring or a multi-criteria analysis. In addition, guidelines could be provided regarding risk and sensitivity analyses, or guidelines on how to allocate costs and benefits of project alternatives to stakeholders involved. Guidelines on the interest rate and economic life, to be used for project comparison, could also be provided.

When all dimensions of the methodology are defined, the assessment can be executed following the described guidelines. Within the assessment step, the KPIs will be determined for the various project alternatives. The obtained KPI values will result in a score for each project alternative for each KPI. A comparison of the different project alternatives can subsequently be performed based on a combination of the results of the KPI assessment.

2.3.2 ASSESSMENT FRAMEWORK SUMMARY FOR THIS STUDY
Following the outcome of the second workshop, together with DEA, DNV has defined the following framework for this study.

2.3.2.1 Scope
The scope of the analysis comprises the entire North Sea with its adjacent countries, namely Denmark, Norway, the UK, Belgium, the Netherlands, and Germany. The analysis is carried out for a single point of time – year 2050, i.e. reflecting how the proposed offshore infrastructure concepts will look in their end state.

2.3.2.2 Scenarios of market development
DNV will apply a single scenarios of market developments building upon its European market model. The details of this model including its assumptions and input sources are given in Appendix B.

The key assumption that reflects the project objective is that the total capacity of installed offshore wind generation in Danish EEZ is equal to 40 GW. This is more than DNV's power market model envisions for DK in 2050 (21.5 GW offshore wind installed capacity). Therefore, it was agreed that in order to maintain the overall balance of offshore wind installed capacity in the North Sea region while increasing Denmark's installed capacity, a redistribution* of neighbour countries' offshore wind installed capacity allocation was needed.

* Only the remaining 18.5 GW (40 GW – 21.5 GW=18.5 GW) were redistributed

Countries	Connected capacity (GW)	Installed capacity in DK EEZ (40 GW)	Connected capacity from DK EEZ (integrated)	Installed capacity in own EEZ (radial)
Belgium	6.0	1.0	1	5.0
Germany	48.4	5.5	6	42.4
Denmark	21.5	21.5**	17	4.5
Great Britain	74.6	8	8	66.6
The Netherlands	34.4	3.0	3	31.4
Norway	12.7	1	1	11.7
TOTAL	**197.6**	**40**	**36**	**161.6**

Table 2-7 Redistribution of offshore wind installed capacity

** 17 GW integrated, and 4.5 GW radial connected

To come up with a way to redistribute the remaining 18.5 GW in Denmark EEZ, the offshore wind installed capacity share of each country within the North Sea region in 2050 was used as a guide. The result is shown in Table 2-7.

Having determined how to distribute the 40 GW across Denmark and neighbouring countries, an open choice is on how to deliver this energy capacity to each country – via cable or pipes?

Based on previous projects, DNV observed that for a system consisting of both electrical and gas infrastructure to be economical, the share of electrolyser capacity out of the total wind generation capacity needs to be around 30-50%. Furthermore, we have adjusted the selected electrolyser size within this range such that the power that needs to be evacuated via cables is a multiple of 2 GW, which is selected as a standard building block for the electrical transmission offshore grid.

The same assumptions on capacity allocation for power and hydrogen are applied to all concepts for a fair comparison.

2.3.2.3 Project alternatives

The project alternatives considered within this study are 4 offshore infrastructure concepts as identified in the previous section.

1. Centralised – Hydrogen onshore
2. Centralised – Hydrogen offshore – Combined Hydrogen and Electrical
3. Centralised – Hydrogen offshore – Dedicated OWF's for hydrogen production
4. Distributed – Hydrogen offshore – Combined Hydrogen and Electrical

These concepts were elaborated to represent the offshore power and hydrogen grid in Danish EEZ in detail.

2.3.2.4 KPI definition

DNV will use the following KPIs within this study. The list of KPIs includes key metrics that allow to compare the different concept. The KPIs are selected based on specifics of the assessment for offshore transmission infrastructure, as explained in section 2.3.1.

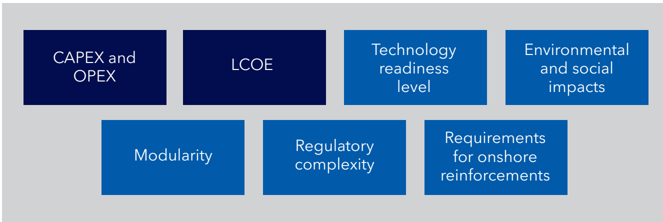


Figure 2-12 List of KPIs (monetised; qualified)

CAPEX and OPEX

CAPEX reports the capital expenditure of a project, (cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, land, preparatory work, designing, equipment purchase and installation). OPEX is based on the project operational and maintenance costs.

CAPEX and OPEX estimations will give an indication of absolute costs as well as the relative costs between the alternatives. Overall CAPEX and OPEX values will be estimated for each alternative based on DNV cost databases. This KPI will be valued quantitatively and will be monetised.

Since the comparison of the offshore infrastructure is made for its 2050 state, DNV will assume everything is built at once. Ideally, one would have to perform an NPV analysis, looking at the annual cashflow from the stepwise network development and evaluate incremental investments (CAPEX) and accumulated costs from the previous years (OPEX). These would have to be discounted based on the year when a certain cashflow occurred.

In practice, DNV will calculate the costs of the final state of infrastructure development, i.e. for how it looks in 2050. Since we do not investigate the stepwise build-out of each concept, looking at the end state is the only way of comparing the costs. In this context, discounting would be misleading, hence we will present the costs in 2021 terms. Whilst this approach does not capture the effect of timing for investments and does not provide an insight into the volume of anticipatory investment required in each concept, it does allow to see which of the concepts is more capital intensive overall.

Learning effects: for each alternative DNV will use 2021 component unit cost values. In reality, most of the components will decline in cost by 2050 due to learning effects, with different level of decline per component type. Since we are not considering stepwise concept development, it would be misleading to apply learning effects.

OPEX: we will calculate OPEX as annual costs to be paid for the operation and maintenance for the full concept infrastructure, corresponding to its end state in 2050. It is not possible to estimate lifetime OPEX because majority of the network will be built before 2050, hence such a calculation would require insights into yearly incremental growth of the infrastructure. As explained earlier, stepwise development is out of scope for this assignment.

LCOE

Levelized cost of electricity reflects the unit cost of each MWh of energy produced over the lifetime of the project. It combines the insights obtained in CAPEX and OPEX assessment with the forecasted energy production output considering the resource availability and curtailment. In order to calculate the LCOE a typical 30-year lifetime and 3.5% discounting rate will be assumed. The following definition of the LCOE will be used:

Equation 1 LCOE

$$LCOE = \frac{CAPEX + OPEX}{Volume_{generation} + Volume_{trade}}, \text{ where}$$

CAPEX – capital expenditure, investment cost estimates for the power transmission and hydrogen infrastructure.

OPEX – net present value of annual operational expenditure for the power transmission and hydrogen infrastructure incurred across the lifetime of 30 years.

$Volume_{generation}$ – net present value of the annual volume of energy generated offshore.

$Volume_{trade}$ – net present value of the annual volume of energy traded through the hybrid connections. In this context, any flow from the onshore to the offshore system is classified as trade seeing that there are no consumers offshore.

In the denominator we include both the volume of generated energy and the volume of traded energy. This reflects the fact that the offshore infrastructure serves multiple purposes, namely delivering wind power to shore and facilitating interconnection between the countries.

Technology Readiness Level (TRL)

The TRL reflects the level of maturity and industrialisation for the technologies forming the basis of a given infrastructure concept. The technical feasibility of a concept can be riskier and more uncertain depending on how mature are the technologies that it builds upon. This KPI will be valued qualitatively based on 2022 state-of-the-art technology.

This will serve as an indication of which technologies would have to mature further for each concept to be implemented. At the same time, low TRL implies higher potential for cost reductions if the technology is actually industrialised. If so, the technology development of the project can constitute large welfare gains for society in general.

Environmental and social impacts
Social and environmental impacts characterise the project impact on (local) populations and environments, often assessed through preliminary studies. When assessing a project's impact on overall socio-economic welfare it is also important to take in to account the impacts it could have on environmentally vulnerable areas, and the distributional effects it can have on local or the general population. We will value this KPI at a high level, qualitatively.

Possible impacts will be identified and analysed, both on a local and general level. Environmental impacts may include damage to natural areas, pollutants etc. Social impacts reflect how will the project affect alternative livelihoods such as the fishing industry, tourism, visual amenity, etc due to construction or operation of the project.

Modularity
Modularity is defined as a feature of offshore infrastructure planning, design and development that:

- Enables expansion to other parts of the North Sea
- Minimises the risk of stranded assets
- Tackles uncertainty in the scale, timing and location of offshore wind deployment
- Enables discrete expansion steps, sufficiently large to achieve economies of scale, whilst respecting limits imposed due to technology developments and system integration
- Facilitates clearly defined interfaces within a hub or between multiple hubs
- Tackles dependencies between the different building blocks and functionalities

This KPI captures:

- different level of upfront design and planning
- different level of anticipatory investment
- complexity of implementation and decommissioning

Modularity will be valued qualitatively. We will reflect on the level of anticipatory investment and necessity of long-term planning horizon that needs to be in place for each of the concepts.

Regulatory complexity
This KPI indicates any bottlenecks or procedural complexities due to regulation, permitting, organisation of stakeholder roles, etc that may affect the timeline and cost of implementation. The 2021 state will be considered.

Concepts may entail technical or organisational features that are not allowed under the current regulatory frameworks and rules; concepts may require longer lead times due to complex interaction between stakeholders and lengthy permitting and connection processes.

This KPI will be valued qualitatively (based on the 2021 situation). This analysis will identify gaps towards deliverability of different concepts, i.e. what needs to change to make the concepts possible by 2050.

Requirements for onshore reinforcements
The alternatives will require different levels of onshore investment to facilitate the evacuation of the power and hydrogen produced in the different alternatives.
The amount of onshore reinforcements needed can impact overall cost of the project, the RES integration level and have environmental and social impacts. We will value it qualitatively.

Overall differences in necessary onshore reinforcements will be identified and analysed per alternative. This applies both to power and gas/hydrogen grid and components. On a high level we will explain which of the concept requires more or less reinforcements and why.

2.3.2.5 Tools
DNV will use its transmission and hydrogen cost databases to estimate CAPEX and OPEX. To value the remaining quantitative and monetised KPIs, PLEXOS® economic dispatch modelling software by Energy Exemplar covering the European market at a zonal level will be used. The qualitative KPIs will be valued based on DNV experience and engineering expertise with reference to trusted sources where relevant.

2.3.2.6 Assessment
The approach to compare projects depends on the type of the assessment (financial vs social) and the extent of monetisation of the KPIs. From an ideal perspective, each KPI should be expressed as much as possible in monetary terms on the condition that objective monetisation parameters can be obtained, and that monetisation is relevant for the KPIs.

The assessment in this study serves to support Danish decision makers. The most cost-effective project alternative is not necessarily the "best" decision from a societal perspective. Not all interests can be expressed in cash and can be weighted in a comparable way. The analysis, therefore, will highlight the consequences of different offshore grid alternatives on broader society. The final decision in the decision-making process will probably be taken by a range of stakeholders, for whom, with the help of the information from the assessment, the discussion can be structured, rigorous and transparent.

3. RESULTS

3. RESULTS

This section contains an overview of our concept analysis per KPI.

3.1 CAPEX and OPEX

The CAPEX and OPEX are estimated taking into account the following primary components of the infrastructure:

ELECTRICAL COMPONENTS
- HVDC converter (offshore and onshore)
- HVDC cable
- DC circuit breaker (DCCB)
- HVAC transformer
- DC gas insulated switchgear (GIS)
- AC (GIS)

SUPPORT STRUCTURES
- Platforms (caisson islands or sand islands)

GAS INFRASTRUCTURE
- Electrolyser
- Pipeline

Detailed explanations of the costs for both electrical transmission and hydrogen production and transport infrastructure are given in Appendix D – CAPEX and OPEX data Assumptions. The bill of materials for each concept comprising a full list of underlying equipment and components can be found in Appendix E – Bill of Materials for CAPEX and OPEX.

Detailed explanations of the input for both electrical transmission and hydrogen production and transport infrastructure are given in Appendix C – Detailed Concepts.

3.1.1 CAPEX - SUMMARY

Figure 3-1 gives an overview of the total capital expenditure (CAPEX) per concept with a high-level breakdown into component types.

Our analysis shows that Concept 1 - Centralised - Onshore Hydrogen results in the highest overall CAPEX at a total of 42.1 bn EUR. Both Centralised concepts with offshore hydrogen (Concepts 2 and 3) production follow closely at apx. 39.5 bn EUR. Concept 4, distributed – Hydrogen offshore – Combined Electricity and Hydrogen is characterised by the lowest total cost of 38.3 bn EUR.

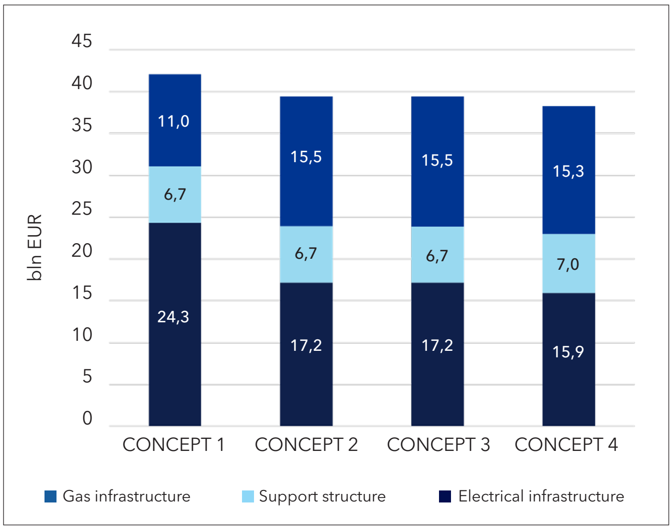


Figure 3-1 CAPEX assessment summary (bln EUR)

We note that the difference between the most and least expensive concepts is 9%. Considering the uncertainty about the cost development towards 2050, the difference can vary. In principle, the obtained values are in the order of magnitude with other cost assessments that have been performed for large scale grids. One example is the PROMOTioN project that has concluded that an average capital cost for the transmission infrastructure integrating 1 GW of offshore wind in the North Sea is equal to 1 bn EUR*.

A detailed breakdown of both CAPEX and OPEX into component types, including all underlying data can be found in Appendix F - Detailed breakdown of CAPEX and OPEX results. Furthermore, a sensitivity analysis based on the varying difference in the cost of offshore electrolysis can be found in the same Appendix.

Detailed concept comparison reveals that the Distributed concept benefits from the reduced cable and pipeline length. Being able to distribute smaller hubs more evenly across the Danish EEZ allows to reduce total distance to onshore connection points in the assumed highly interconnected international system. Centralised concepts are less advantageous as one should ensure that wind farm

* https://www.promotion-offshore.net/fileadmin/PDFs/D12.4_-_Final_Deployment_Plan.pdf

array cables can reach large hubs. This entails that the hubs need to be placed in the middle of the lease area, often further from onshore connection points. We expect that Centralised concepts will have the same adverse effect on array cable costs, since hubs are on average further from individual wind farms than they would be in the Distributed concept. DNV finds this result to be general for the concept, although the exact cost difference may depend on the implementation.

The cost reduction due to a more optimal co-location of small hubs with relation to onshore connection points and wind farms is partially offset by more expensive support structures, where large artificial islands deployed to accommodate 36 GW of offshore wind result in the economies of scale, compared to smaller steel platforms in the Distributed concept.

Furthermore, the CAPEX evaluation shows that onshore hydrogen production is likely to be more expensive than offshore, regardless of whether the offshore electrolysers are coupled to a wider power network or powered directly from dedicated individual windfarms (Concepts 2 and 3 have negligible difference in the total CAPEX). The difference between Concept 1 and 2 is around 6%. Whilst offshore electrolysers are expected to be more expensive than their onshore counterparts (this is explained in detail in Appendix D – CAPEX and OPEX data Assumptions), the savings in converters are of a much larger scale. The latter is large enough to compensate the effect from higher cumulative cost of cables and pipelines in concepts with offshore hydrogen production, when compared with the onshore case.

Finally, the marginal savings in Concept 3 with respect to Concept 2 come from the lack of necessity to have some extra offshore HVAC switchgear which connects electrolysers to a wider grid in the latter case. Since the cost of this equipment is minor compared to the overall CAPEX, DNV is of an opinion that the concepts with dedicated hydrogen connections from some of the windfarms should not be pursued in the majority of cases. In contrast, the operational benefits and flexibility provided by interconnected power infrastructure and electrolysers can be sizeable.

3.1.2 OPEX - SUMMARY

Next to the CAPEX assessment, DNV has evaluated the expected annual operational expenditure (OPEX) for managing and maintaining the infrastructure in each of the concepts. Our investigation shows similar trend in terms of relative performance, whereby the Centralised concept with onshore hydrogen (Concept 1) production entails the highest operational costs at a level of 660 mn EUR per year. Centralised concepts with offshore hydrogen production reach 566 mn EUR (Concepts 2 and 3), whilst the Distributed concept with offshore hydrogen production is the cheapest at 543 mn EUR per year (Concept 4).
In contrast with CAPEX estimates, the largest contributors to the annual OPEX are HVDC cables and electrolysers, together accounting for just under 70% of the total for all concepts.

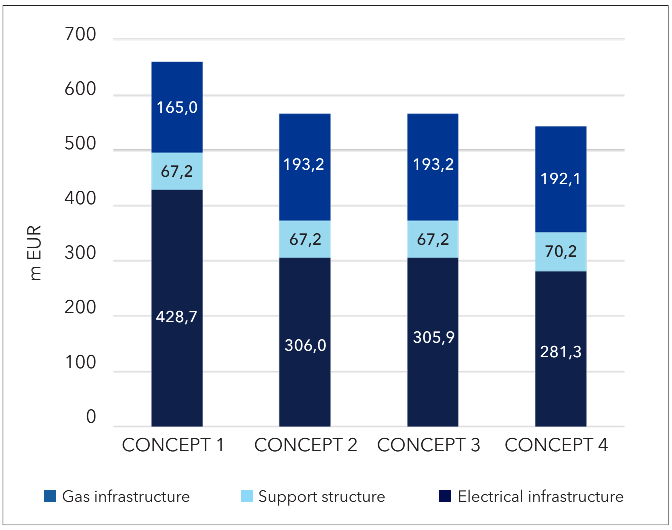


Figure 3-2 OPEX assessment summary (m EUR)

3.1.3 SENSITIVITY TESTS

3.1.3.1 Offshore electrolyer costs

Our assessment assumes that the cost of offshore electrolysers is 5% more expensive than that of the onshore. Considering that electrolysers are still an immature technology, we have conducted a sensitivity analysis to explore how the overall CAPEX difference between the concepts changes with increase in the cost difference between onshore and offshore electrolysis costs. The outcomes are shown in Figure 3-3 and Table 3-1. It can be seen that the conclusion on the overall advantage of offshore to onshore hydrogen production in terms of the total cost holds even at the level of 20% difference between the costs of offshore and onshore electrolysis.

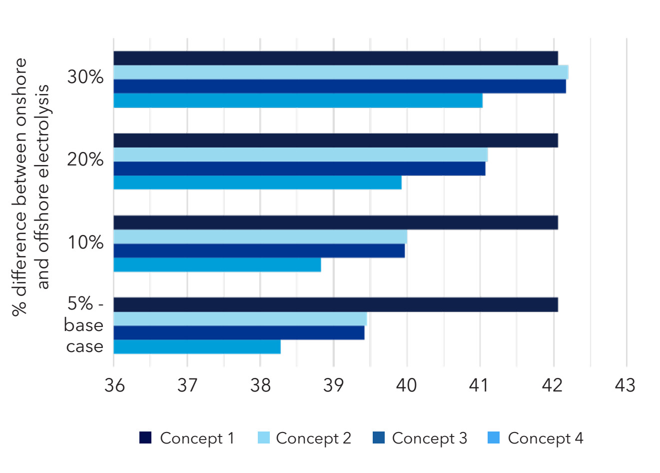


Figure 3-3 Offshore electrolysis cost sensitivity (bln EUR)

	CONCEPT 1	CONCEPT 2	CONCEPT 3	CONCEPT 4
5% - base case	42.06	39.45	39.42	38.28
10%	42.06	40.00	39.97	38.83
20%	42.06	41.10	41.07	39.93
30%	42.06	42.20	42.17	41.03

*Table 3-1 Offshore electrolysis cost sensitivity (bln EUR) **

3.1.3.2 Standard size of electrical connections

Another sensitivity assessment that we have performed is related to the size of electrical connections assumed as a standard block. Whilst we have used 2 GW blocks as a standard, it is important to understand the impact from the economies of scale that this provides compared to e.g. 1 GW and 0.5 GW blocks. This is shown in Figure 3-4, where the part of costs related to the electrical equipment is scaled accordingly to the unit cost difference of 2 GW with 1 and 0.5 GW converters and cables.

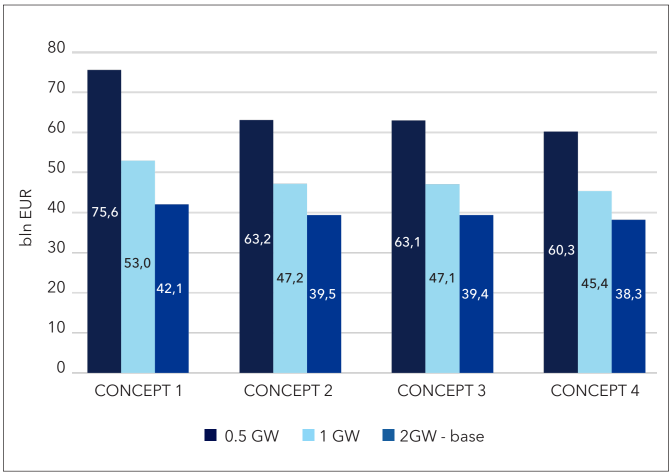


*Figure 3-4 Size of electrical blocks sensitivity (bln EUR) **

Shift from 2 GW to 1 GW blocks results in 18% to 26% change in CAPEX depending on the concept. A similar shift from 2 GW to 0.5 GW blocks leads to even higher difference in the range of 57% to 80%.

3.1.3.3 Detailed design sensitivity for Centralised concepts

Next, we have additionally explored the impact of different detailed concept design for the cost difference between Centralised Concept 2 and Distributed Concept 4.
We have made the following changes to Concept 2 detailed design:

- Reducing capacity of connections from hub A to GB from 2x2 to 2 GW (-380 km)
- Adding 2 GW connection from hub B to GB (+365 km)
- Connecting hub A to NL via 2 GW connection of 338 km (+338 km)
- Reducing capacity of connection from hub B to DK from 2x2 to 2 GW (-235 km)
- Removing 2 GW connection from hub D to NL and adding 2 GW connection to DK (-298+66 km)

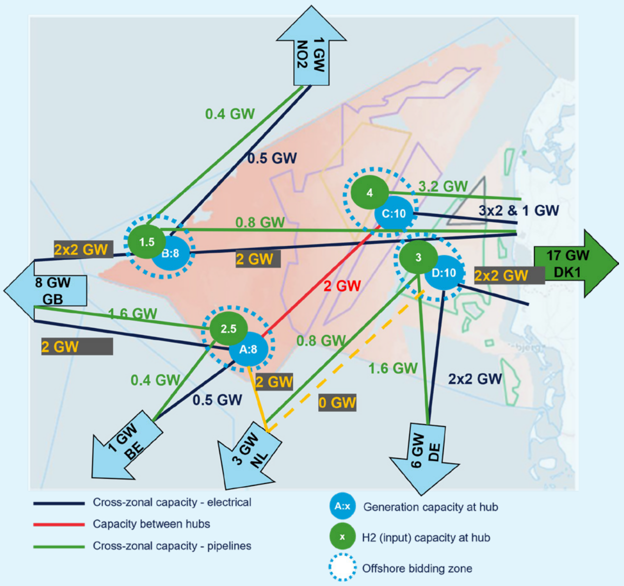
This results in the total reduction of 2 GW cable length by 144 km. The changes are illustrated in Figure 3-5 which is an updated version of Figure 2-8 corresponding to Concept 2.

The impact on the CAPEX of Concept 2 is the reduction by 0.36 bln EUR. A similar reduction would be achieved for Concept 3.

For Concept 1 the reduction is higher – driven by 500 km decrease in 2 GW cable cost and 212 km increase in 1.5 km cost leads to the savings of 0.78 bln EUR for Concept 1.

This makes the difference between Concept 2 (39.1 bln EUR) and Concept 4 (38.3 bln EUR) to be equal to 0.8 bln EUR which corresponds to 2%. A summary is given in Figure 3-6.

* The hub placements and cable lengths have not been optimised. This limits comparability between concepts, especially comparing Concept 4 to other concepts.



Characteristics	Concept 2
Number and size of hubs	2 hubs of 10 GW each 2 hubs of 8 GW each
Total cable length (km) per capacity level	Cable 2 GW > 2877 (2733) Cable 1.5 GW > 0 Cable 1 GW > 0 Cable 0.5 GW > 813
Total pipeline length (km) per capacity level	Pipeline 0.4 GW > 813 Pipeline 0.8 GW > 533 Pipeline 1.6 GW > 657 Pipeline 3.2 GW > 76
Electrolysers location	Offshore
Electrolyser powered by	Offshore wind farms (hubs), and energy from the wider grid

Figure 3-5 Sensitivity for detailed "Centralised - Hydrogen offshore - Combined Hydrogen and Electrical" concept (changes from the original are marked in orange)

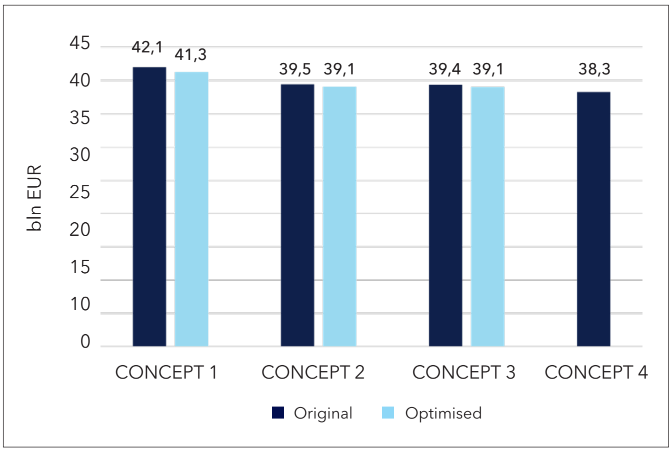


Figure 3-6 Optimisation of detailed design sensitivity (bln EUR)

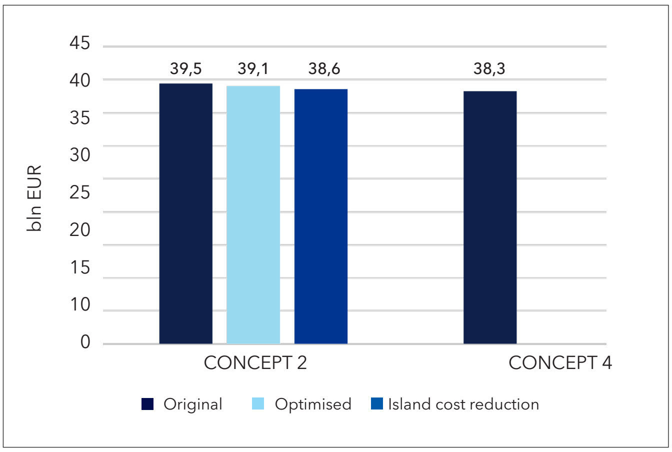


*Figure 3-7 Optimisation of detailed design and island cost sensitivity (bln EUR) **

3.1.3.4 Offshore island cost sensitivity

Furthermore, we have considered how a more optimistic view on the cost of offshore islands will affect the difference in CAPEX between the Centralised Concept 2 and Distributed Concept 4. Whilst our initial assessment considered the cost of 10 GW sand island to be equal to 1800 m EUR, other studies suggest that large scale islands can come at a lower cost**. Quadrupling the capacity of an islands leads to doubling of its cost. Taking a middle ground we conduct a sensitivity, assuming the cost of 10 GW island to be equal 1560 m EUR.

This leads to a reduction in the total CAPEX of Concept 2 from 39.5 to 39 bln EUR. A similar reduction would be achieved for Concept 1 and 3.

Combined with the previous sensitivity test of a detailed Concept 2 design optimisation, the total CAPEX reduction that could be achieved would bring the cost of Centralised Concept 2 to 38.6 bln EUR, only 300 mln EUR more expensive than Distributed Concept 4, a difference that is negligible considering the conceptual nature of this study. This is illustrated in Figure 3-7.

* The hub placements and cable lengths have not been optimised. This limits comparability between concepts, especially comparing Concept 4 to other concepts.
** https://ens.dk/sites/ens.dk/files/Vindenergi/a209704-001_cost_benefit_analyse_endelig_version.pdf

3.2 Offshore power network utilization

In all four concepts described, considerable amounts of renewable energy are generated and fed into the power system. There will, however, be differences in how much energy the concepts allow to deliver to shore, as well as how efficiently the facilitate trade between the markets is.

Here, DNV summarises how well the different concepts contribute to power system utilisation by closely examining two indicators:

- Generation and curtailment: How much renewable energy does each concept integrate into the power system?
- Interconnection flows: How much trade does the transmission capacity in each concept facilitate?

The outcomes of the modelling can be found in the table below. All in all, Concept 3 results in the highest power system utilisation when these indicators are considered*. This is likely due to the fact that Concept 3 has the lowest levels of curtailment among the concepts. Concept 2, which is an offshore hybrid concept where the renewable energy can be evacuated both as electrons and molecules gives the second highest results. The results for each of the indicators are explained more in detail below.

Generation and curtailment

The four concepts lead to different amounts of electricity generation even though the installed capacity is the same. This reflects that the generation varies somewhat because of available wind resources and that the concepts are subject to varying degrees of curtailment.

Curtailment of renewable energy generation occurs when not all of the potential generated energy is integrated into the power system. Renewable curtailment will typically occur when OWFs can generate electricity but aren't able to because there's not sufficient transmission capacity or demand to offset it.

Essentially, the differences in annual generation and curtailment levels between the concepts reflects differences in how the demand, generation and available grid capacity are optimised given the differences in offshore grid design.

In Concept 1 curtailment is high and generation is low because the offshore assets are solely dedicated to electricity generation and transmission. In practice this means that Concept 1 is the most affected by the generation and demand fluctuations onshore, and that the onshore electrolysers create different flow patterns compared to the other concepts.

In Concept 2, there is a shift in demand from onshore to offshore as the electrolysers now are placed offshore. These offshore electrolysers use electricity both from the grid and directly from the wind farms which reduces the curtailment levels and increases generation compared to Concept 1.

In Concept 3, this demand shift is made even stronger because parts of the generated electricity is used solely for hydrogen production. The relevant sections of the OWFs are disconnected from the offshore transmission grid which means the generation isn't affected by the surrounding power system. As a consequence, Concept 3 has the highest generation with the lowest curtailment levels of all the concepts.

In Concept 4, the hubs are smaller and there are more interconnectors, which means that the offshore grid is connected to more and different bidding zones compared to the other concepts. In this concept, generation decreases and curtailment is higher compared to a more centralised Concept 2. The difference is likely due to different locations for the OWFs and that demand and generation profiles differ across the connected bidding zones. Together with more and smaller interconnectors, this increases the likelihood and prevalence of curtailment.

Overall, we see that Concept 3 has the highest generation with the lowest curtailment levels. The main reason is that in this concept a share of the generated electricity is used solely for hydrogen production and is disconnected from the grid meaning that it is unaffected by the situation in the surrounding power system. As one then can expect, the lowest generation, with consequently the highest degree of curtailment, is observed for Concept 1 where the offshore assets are solely dedicated to electricity generation and transmission. The flexibility that Concepts 2 and 4 provide in either evacuating the generated energy as electrons or hydrogen molecules, constitutes a middle ground compared to Concepts 1 and 3. This is also reflected in the results.

	CONCEPT 1	CONCEPT 2	CONCEPT 3	CONCEPT 4
Volume generation annual (GWh)	112,691	124,247	131,960	120,265
Volume trade annual (GWh)	18,735	19,171	13,279	17,421

Table 3-2 Relevant estimates - contributions to power system efficiency

* Note that these indicators will not necessarily give a full picture of what overall benefits for society the concepts will bring. These are two indicators that DNV opines are important to consider.

Interconnection flows
The amount of interconnection flows is an important aspect to consider when comparing the concepts as they not only integrate the offshore renewable energy to the power system, but also facilitate trade between the connected countries and OBZs. The trade contributes to larger socio-economic benefits for the North Sea region as a whole, and this should be considered when comparing the concepts. As there has not been performed an optimization in terms of the topology of the cables and pipelines, there is however some uncertainty about the total level of interconnection flows that can be realised through the concepts. They nevertheless give a good indication of the differences between the concepts.

The results from the interconnection flow estimates give the opposite results of that of generation. The reason is that as the transmission capacity is used for trade purposes, generation must be curtailed as it has no way of being evacuated. Here, Concept 3 gives the lowest value, whilst Concept 1 yields a better outcome in trade facilitation. The flexibility in evacuating the energy either in form of electrons or molecules proves a benefit as Concepts 2 and 4 give the highest values in interconnection flows.

3.3 LCOE of transmission infrastructure

In order to calculate the Levelized Cost of Energy (LCOE), the CAPEX, OPEX, generation volume and volume of traded energy are discounted at 3.5% basic rate over the lifetime of 30 years. This is typical for the considered infrastructure based on DNV experience. The outcomes of our estimation, including a sensitivity analysis for a 5% discount rate are shown in Figure 3-8. Note that these LCOE estimates only reflect transmission infrastructure but do not take into account the generation side.

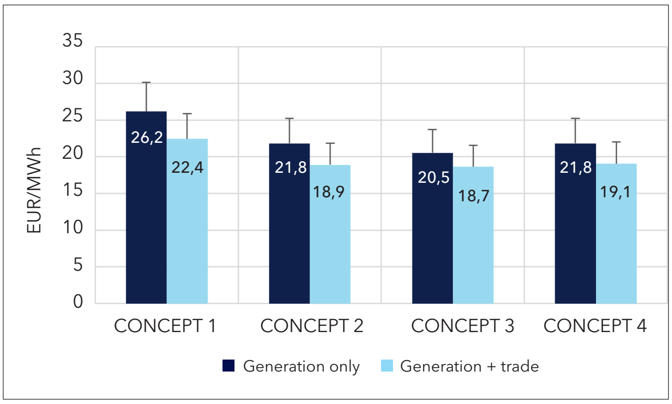


Figure 3-8 LCOE results (EUR/MWh) of transmission infrastructure

The "Generation only" result considers the volume of generated energy and ignores the potential utilisation of the offshore network for interconnection purposes. The "hybrid" case on the other hand, also takes into account the dual-purpose nature of the offshore networks and includes the possibility for power trade between countries. The results are presented in Table 3-3.

The data as in Table 3-4 was used as inputs into the LCOE calculations in line with Equation 1 shown in section 2.3.2.4.

The difference in generation volume between the concepts is mainly caused by curtailment. In most cases, curtailed generation creates additional available transfer capacity which can be utilised for trade, as explained in section 3.2.

In addition, we have considered a longer equipment lifetime of 70 years. The results of our estimate are given in Figure 3-9.

	CONCEPT 1	CONCEPT 2	CONCEPT 3	CONCEPT 4
Generation only (3.5%)	26.2	21.8	20.5	21.8
Hybrid (3.5%)	22.4	18.9	18.7	18.7
Generation only (5%)	30.1	25.2	23.7	25.2
Hybrid (5%)	25.8	21.8	21.6	22.0

Table 3-3 LCOE results (EUR/MW) of transmission infrastructure

	CONCEPT 1	CONCEPT 2	CONCEPT 3	CONCEPT 4
Capex (mEUR)	42,064	39,451	39,421	38,278
Opex annual (mEUR)	€ 661	566	566	544
Volume generation annual (GWh)	112,691	124,247	131,960	120,265
Volume trade annual (GWh)	18,735	19,171	13,279	17,421

Table 3-4 LCOE inputs

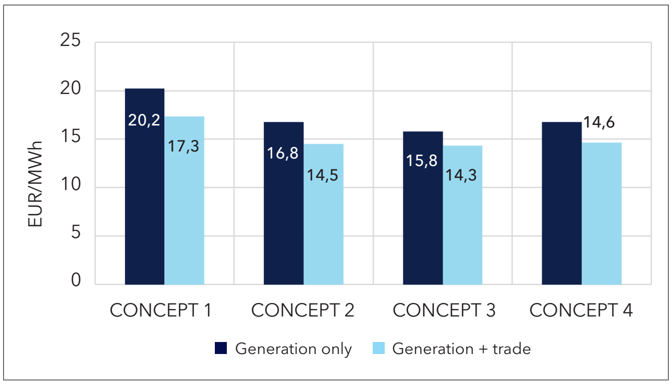


Figure 3-9 LCOE (EUR/MWh) of transmission infrastructure assuming 70-year lifetime

3.4 Technology readiness level

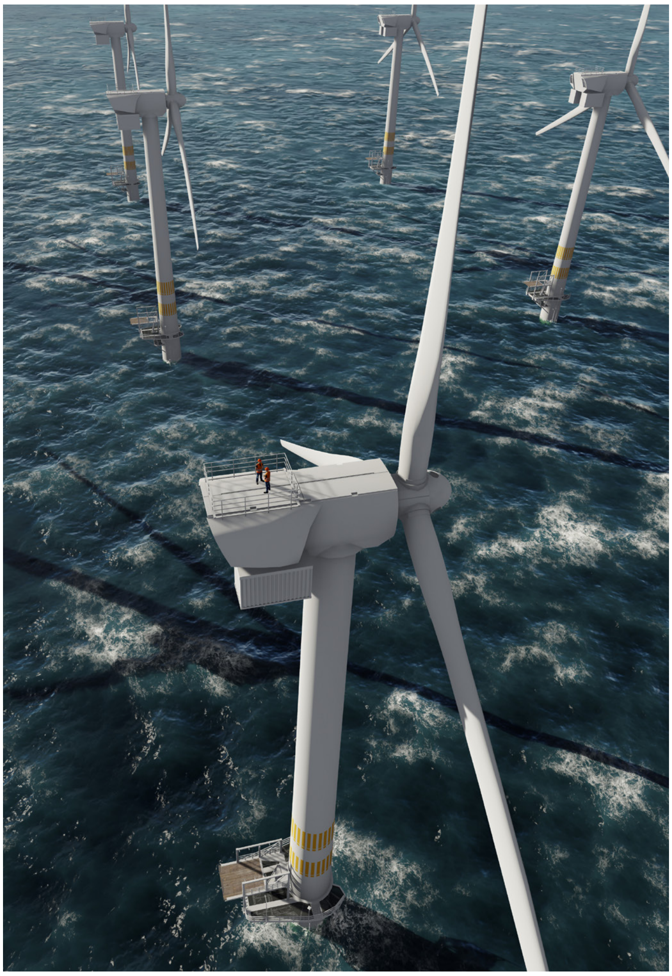
Within the technical designs envisaged by the developed topologies DNV expects all necessary technical components to become available before 2050. Therefore, within the technology readiness level, we focus on the equipment that in 2022 is not yet industrialised and therefore would require closer monitoring by the planning agencies and developers.

The intent of this KPI is to flag if certain concepts rely on components that are still immature to a higher degree than the other concepts. We consider the following major building blocks for the offshore infrastructure:

TRANSMISSION TECHNOLOGY
- HVDC converters offshore and onshore
- HVDC cables
- HVAC cables
- DC gas insulated switchgear (GIS) - more in centralized concepts, more in H2 onshore
- DC circuit breakers (DCCB) - more in centralized, more in H2 onshore

HYDROGEN TECHNOLOGY
- Electrolysers at GW scale offshore and onshore - only in H2 offshore concepts. Larger in centralized concepts but can be modularized.
- Pipelines

SUPPORT STRUCTURES
- Platforms
- Caisson islands
- Sand island



In the TRL assessment in Table 3-5 DNV comments on the industrial readiness level of each of the different concepts. We mark with orange colour areas where development needs to take place between 2022 and 2050 to make those concepts feasible. A green colour indicates that the necessary technology is sufficiently mature already today. At present, we expect all necessary developments to materialise by 2050, with little to no risk to the technical feasibility of a concept.

The explanation of TRL scale is given in Appendix G - Technology Readiness Level scale.

DNV concludes that whilst all concepts are expected to be technically feasible towards 2050, Concepts 2 and 3 require some further technology maturing across two major component types, hence they are ranked lower than Concept 1 and 4.

Table 3-5 TRL assessment

<table>
<tr><th></th><th>CONCEPT 1
Centralized - H2 onshore</th><th>CONCEPT 2
Centralized - H2 offshore - combined electricity and H2</th><th>CONCEPT 3
Centralized - H2 offshore - dedicated OWF's for hydrogen production</th><th>CONCEPT 4
Distributed - H2 offshore - combined electricity and H2</th></tr>
<tr><td>HVDC Converters</td><td colspan="4">For onshore, both VSC and LCC HVDC converters are applicable, while for offshore, LCC converters are incompatible, and only VSC converters are considered. 320 kV converters up to 1400 MW are widely applied as a mature technology (TRL9) nowadays. 525 kV 2 GW HVDC converters for onshore and offshore are featured in all concepts. This is a conservative choice based on the technology that will be available by 2030 and is already planned in several project by TSOs and developers (TRL6). Meanwhile, 525 kV VSC converters up to 1400 MW have been successfully commissioned and operated in offshore, which is technically mature (TRL8-9). 800 kV VSC converters and 1100 kV LCC converters have been used in onshore projects in China. However, HVDC converters with such voltage level are not yet available for offshore. HVDC converters with DC voltage higher than 525 kV are expected to become available in Europe in the coming 5-10 years for individual projects. However, direct connection of projects operating at different DC voltages is not feasible yet and is not expected in the mid-term. This would require high power DC/DC transformers or connecting via and HVAC transformer. The former is being technically immature (TRL2-3) and the latter resulting in large extra costs due to multiple AC/DC conversion steps required. In addition, so far all of the HVDC systems in offshore practice are point-to-point with single vendor. With multi-terminal HVDC systems, especially when the converters are supplied by different vendors, there will be the interoperability issue. This issue is caused by the situation that, different vendors provide their own control systems into the same system. One control system could control its own converters but cannot synchronize and collaborate with other control systems. Interoperability issue is under study now and could be solved technically. However, more effort is required on solving non-technical issues such as regulatory and ownership etc.</td></tr>
<tr><td>HVDC Cables</td><td colspan="4">For distance longer than 100 km, HVDC cables are used for transporting the energy. The VSC converter technology has led to the adoption of extruded cables for HVDC transmission systems. 320 kV 2 GW HVDC extruded cables have been used in many offshore projects, which is a mature cable technology (TRL9). 400 kV DC extruded cables have been qualified but with limited applications and operating experience (TRL8). 525 kV extruded cables are available with up to 2.6 GW, which are being developed by several cable manufacturers. So far, the 525 kV cables have not yet been operated in any pilot project. However, it is expected to be available by 2022 for offshore applications, viewed as semi-mature technology (TRL7-8). 600/640 kV extruded cables are under development now with up to 3 GW. MI (mass impregnated) DC cables are also available up to 525 kV with 600 kV under development. 525 kV was chosen as a standard building block for all concepts, making them feasible with today's available technology. The same reasoning regarding combining different voltage levels as for the converters applies.</td></tr>
<tr><td>HVAC Cables</td><td colspan="3">HVAC cables are the most economically and technically efficient method for transporting energy from offshore to the coast with the distance smaller than 100 km. For offshore applications, three core AC cables are dominating instead of single core AC cables, considering the cost and the footprint. The optimal AC voltage applied in offshore applications is 220 kV up to 100 km. With longer distance or higher voltage, much higher reactive compensation is required. Extruded HVAC cables are available at different voltage levels up to 400 kV for offshore applications. 132 kV and 220 kV HVAC cables are mature (TRL9). 400 kV HVAC single-core cable systems have been applied in several projects, and 420 kV XLPE HVAC cable technology is being further developed.
All Centralised Concepts are heavily dependent on the utilisation of 132 kV HVAC array cables to enable direct connection of the windfarms to larger hubs. It is possible to implement these concepts with 66 kV cables, but it will require intermediate step-up HVAC platforms resulting in extra cost. As such 132 kV HVAC cables are available and mature, although have not been used as inter-array cables.</td><td>Distributed concept can be implemented with 66 kV array cables because hubs connect smaller generation capacity and can be located closer to the windfarms.</td></tr>
<tr><td>DC GIS</td><td>Centralised concept with Hydrogen onshore features the largest number of offshore DC GIS due to the highest level of interconnection between the different links connecting hubs to shore and to each other.</td><td colspan="2">Same reasoning applies for the other Centralised concepts, although shifting hydrogen production to offshore reduces the number of electrical connection and therefore the number of GIS. As such it still requires GIS.
HVDC GIS for use in HVDC transmission has been under development for several years. There are several manufacturers having HVDC GIS available for the market in the range of 250 kV to 550 kV. So far, the HVDC GIS being used in the real project is operating at a maximum voltage of 320 kV. Thus, the maturity level of HVDC GIS is relatively high. However, there is no international standard for the specification requirements and test procedure for HVDC GIS.</td><td>Distributed concept features the lowest amount of GIS. At some hubs, due to their small size, GIS is not required as such. Therefore, this concept is the least dependent on the industrialisation of this technology.</td></tr>
<tr><td>DCCB</td><td>The same explanation and difference between Concepts as for DC GIS.</td><td colspan="2">The same explanation and difference between Concepts as for DC GIS.
DCCB technology has reached TRL 7 in Europe. DCCBs have not been used at transmission levels in Europe since almost all the VSC-HVDC systems in operation today have been developed as point-to-point systems. The available DCCBs are technically ready for application in real projects, which however, is not yet deployed practically. DCCBs have been successfully commissioned and operated in several projects in China.</td><td>The same explanation and difference between Concepts as for DC GIS.</td></tr>
</table>

Table 3-5 TRL assessment (continued)

	CONCEPT 1 Centralized - H2 onshore	CONCEPT 2 Centralized - H2 offshore - combined electricity and H2	CONCEPT 3 Centralized - H2 offshore - dedicated OWF's for hydrogen production	CONCEPT 4 Distributed - H2 offshore - combined electricity and H2
Electrolysers at GW scale	The largest onshore electrolyser for hydrogen production is currently 20 MW in Canada*. Double and triple digit MW plants are expected towards 2025, but GW scale plants still need more development.	Scale up for onshore electrolysers is currently the focus of manufacturers and although some are looking at offshore application, this still requires more development and research. Currently it is unknown how suitable onshore electrolysers are for offshore conditions. The main challenge will be the integration with other components (wind turbine, desalination, etc.) as an integrated and reliable system. Intermittency of power supply, black start capabilities when a grid is not available, operability and maintainability will be some of the main aspects. Pressurized alkaline and PEM are both possible solutions for offshore application although the effects of waves (rocking) on the electrolyte in alkaline could limit the application of this technology on floating structures.		
Offshore hydrogen pipelines	Not required.	Pipelines have been applied offshore for many years and for multiple gasses/fluids. Offshore pipelines specific for hydrogen are not yet applied and there are still gaps in standards and certification. However, the topic is very well known and DNV is included in multiple ongoing projects to solve these gaps for both greenfield pipes and the re-use of existing.		
Steel platforms, caisson islands, sand islands	Centralised Concepts are expected to be based on sand islands or caisson islands, depending on the water depth. Steel platforms have advantages at higher water depth but are limited to lower ratings of ca 2 GW per platform. Where larger HVDC converter or electrolyser capacities need to be installed, multiple platforms will be required if the water depth is too high. Otherwise, it is possible to make use of island structures which are more scalable and expandable to larger hosting areas, sufficient for several GWs of capacities. As such all three support structure technologies are considered to be technically mature. The industry has seen example of implementing each of them, hence no differences between the concepts in terms of support structure technology readiness level.			

* https://www.rechargenews.com/transition/worlds-largest-green-hydrogen-plant-inaugurated-in-canada-by-air-liquide/2-1-952085

3.5 Environmental and social impacts

Overall, DNV acknowledges the following main environmental and social impacts of the main characteristics in our four concepts:

- Distributed concept – larger environmental impact due to cable laying and construction, larger impact in coastal areas due to a higher number of landfall points. Larger impacts due to high number of offshore hubs. More assets generally leading to larger footprint and impacts.
- Centralised – adverse environmental impacts depending on the type of support structure selected for large hubs.
- Offshore hydrogen – potential for reduced offshore environmental impacts, if possible to re-utilise existing gas pipelines.
- Onshore hydrogen – large quantity of new cable trenches needs to be made, with high negative impacts on the seabed.

In this KPI analysis DNV opts for a qualitative approach to compare the impact of the different concepts using the number of landing points, length of cable and pipe underground submarine trenches and length of cables and pipelines as a proxy.

An underground/submarine cable or a pipeline may run through environmentally 'sensitive' areas. This could lead to an irreversible impact on the seabed and marine life, even with implemented mitigation measures. Further, as the number of onshore landing points is reduced, so will be the detrimental impacts on the environment during construction and operational phases.

Based on DNV experience in engaging with local communities, the biggest threats for the population of coastal areas are perceived to be:

- The disruption during construction phase of cable route (construction of sub-stations);
- Long term impact associated with permanent/semi-permanent large structures (i.e. landscape and visual impact);
- Enduring adverse impacts resulting from permanent onshore infrastructure and its inappropriate siting;
- Lack of coordination between infrastructure projects and
- Inadequate mitigation and compensation.

The construction phase is seen as the most disruptive for local communities. Onshore work of 3-5 years is expected with construction and Heavy Goods Vehicle movements for the next ~10 years. It is recognised that it is not realistic to avoid local new connections when connecting offshore wind into the local electricity transmission system, but grid connection should be more strategic/coordinated to minimise any onshore impacts.

To compare the concepts within this assignment we calculate the following proxies:

1. Connection points number – total number of cable circuits and pipes brought onto shore. Connections between hubs are not taken into account. Each individual DC cable circuit and pipe is calculated even if they follow the same route. The latter is done to reflect the number of onshore substations/converters or hydrogen terminals that will have to be built.
2. Total length of subsea trenches – total length of cable and pipeline routes connecting hubs to other hubs or to shore. This can be seen as a sum of the length of all lines shown in Figure 2-7, Figure 2-8 and Figure 2-10 where we distinguish between cable routes and hydrogen pipe routes. This reflects how much subsea work and operations will have to be carries during the construction phase for cable and pipeline laying.
3. Total length of cables – total length of cable circuits connecting hubs to other hubs or to shore. Unlike in the previous item, this adds up the length of cables for each individual circuit, hence this number will always be higher or equal than the sum of trenches required for cables. This reflects how many assets will be built at the seabed.
4. Total length of pipelines – total length of hydrogen pipelines connecting hubs to shore. All hydrogen connections are assumed to consist of a single pipe. This reflects how many assets will be built at the seabed.

The outcomes of the comparison are given in Figure 3-10. Our evaluation shows that Concept 1 results in overall best performance. The number of connection points in Centralised concepts is 21 against 22 in the Distributed Concept 4. The total length of subsea cable and pipe trenches is far lower in Concept 1 as it only features power cables since electrolysers are located onshore. We assume that some of the parallel cable circuits can laid on the seabed within the same installation campaign, thereby minimising adverse impact on marine environment. In this context onshore hydrogen production can reduce environmental impact offshore.

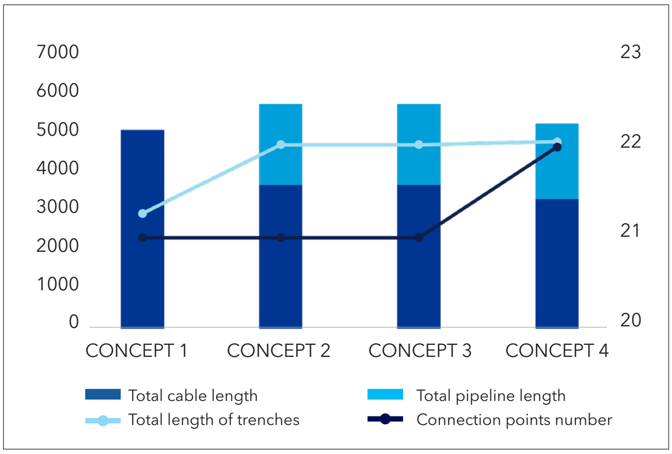


Figure 3-10 Environmental and social impacts. Asset count per concept.

Looking at how Centralised and Distributed concepts compare when hydrogen production is offshore, we find that Distributed Concept 4 results in a slightly higher total length of trenches albeit lower sum of cable and pipeline lengths. The former is a direct outcome from the relatively higher number of hubs and connection routes. The latter stems from the fact that the location of hubs is optimised to make them closer to the production and shore, than in the Centralised concepts, thereby reducing the overall length of energy transmission infrastructure.
The underlying data is given in Table 3-6.

Onshore hydrogen production, as in Concept 1, and strategically located smaller hubs, as in Concept 4, can lead to an overall reduction in the number of onshore connection points and total length of offshore transmission infrastructure, respectively**. Nevertheless, significant number of new onshore electrolysers, in Concept 1, and offshore support structures, in Concept 4, will have to be built. DNV, therefore, notes that whilst some level of environmental and social impact reduction can be achieved, it will not be possible to accomplish a major minimisation of those impacts. Often, an impact will be shifted from one asset class (e.g. shorter cables but more support structures) or from onshore to offshore (pipelines offshore but no electrolysers onshore). It is possible that stronger objections from local stakeholders or permitting limitations are received in a certain area. As the above comparison shows, this could be mitigated by proper offshore infrastructure design.

3.6 Modularity

There is a number of reasons for why modular development of offshore hubs is a preferred method of planning, designing and building interconnected offshore hub-and-spoke projects. In this section we present the main rationale that justifies the need for modularity. The main driver is to minimise the system costs for a final consumer, at the same time ensuring required levels of operational security and supporting high levels of offshore wind integration.
The first reason for why a non-standard method to offshore hub development is needed is future uncertainty. This concerns uncertainties in:

a) the scale of offshore wind generation to be connected to individual countries
b) the location of wind lease areas
c) the timing of windfarm and hub development
d) the desired level of interconnectivity between countries and offshore hubs
e) the balance between electrical and gas infrastructure offshore
f) the state-of-the-art technology capability
g) system integration limits

In this context, a modular approach to hub development must allow to manage these uncertainties and facilitate development when the end state is not perfectly known. Furthermore, offshore hubs are expected to evolve with time. This means expanding by means of connecting additional offshore wind generation, becoming connected to other hubs or new onshore points, or adding new functionalities such as power-to-gas conversion. The ability of a hub to expand can be either limited or fostered by its initial design.

	CONCEPT 1	CONCEPT 2	CONCEPT 3	CONCEPT 4
Connection points number	21	21	21	22
Total length of trenches (km)	2,957	4,725	4,725	4,801
Total cable length (km)	5,108	3,690	3,690	3,337
Total pipeline length (km)	0	2,079	2,079	1,931
Number of hubs	4	4	4	9

*Table 3-6 Environmental and social impacts. Asset count per concept. **

* The hub placements and cable lengths have not been optimised. This limits comparability between concepts, especially comparing Concept 4 to other concepts.
** We note that the location of hubs and interconnector lengths has not been optimised for the purpose of this study, hence uncertainty in the general applicability of this outcome.

Considering the benefits of interconnected systems, it is likely that hubs will be connected to multiple points, whether by means of electrical cables or pipelines for transporting green gas. At the same time, it is unlikely that all provisions for expansions and additional connections will be in place when a hub is initially built. Conversely, we expect that hubs will grow gradually and the large North Sea energy system comprising multiple hubs will be built step-by-step, similar to how the European onshore grid was developed over the time span of several decades. Hence, it is important that a hub is built in a way that caters for future expansions and is not completely inflexible towards new developments. This expandability is an inherent property of the proposed modular planning approach.

Offshore energy hubs are planned to have a wide range of functionalities. This includes not only transferring power from an offshore windfarm to shore, but also providing interconnection capacity, managing power flows, converting power to gas, and potentially even storing energy offshore.

Each of the above-described functions requires its own equipment and infrastructure to be part of the hub. Even though all this equipment is part of a larger single energy system, within a single hub the equipment shares the same support structure, it can be owned and operated by the same party and may be limited by other factors. Offshore energy hubs are therefore complex systems, with numerous technical and other dependencies between key design decisions.

Whilst modularity can be considered at the North Sea-, single hub- or component level, within this assignment the goal is to compare the North Sea infrastructure concepts. In order to evaluate the concepts against this KPI, DNV suggests a range of secondary indicators that characterise how modular is a certain concept at the highest planning level – North Sea. We therefore deliberately ignore detailed hub design considerations as those can be adapted regardless of the adopted concept. This overview is given in Table 3-7.

<table>
<tr><th></th><th>CONCEPT 1
Centralized - H2 onshore</th><th>CONCEPT 2
Centralized - H2 offshore - combined electricity and H2</th><th>CONCEPT 3
Centralized - H2 offshore - dedicated OWF's for hydrogen production</th><th>CONCEPT 4
Distributed - H2 offshore - combined electricity and H2</th></tr>
<tr><td>Optimized planning horizon</td><td colspan="3">Centralised concepts require longer planning horizon as they aim to integrate larger amounts of offshore wind. There is an inherent uncertainty in the future developments as the planning horizon increases. This uncertainty brings risks and makes the concept d esign less modular, since many aspects have to be decided upon in the beginning of the planning period with less opportunities for a change in a later stage.</td><td>Distributed concept is characterised by smaller size of hubs/building blocks. Therefore, the period between the decision to build and operation is significantly reduced. Infrastructure roll-out can be better aligned with wind farm installation, allowing for possible changes from one wind farm project to another.</td></tr>
<tr><td>Support structure expandibility</td><td colspan="3">Centralised concepts feature larger hubs that are planned to accommodate a lot of infrastructure for converting and transporting the energy produced offshore. DNV expects that the support structures utilised for the offshore hubs of 8-10 GW will be designed with larger space margins, therefore having more space for the addition of new components or interfaces for future expansion (e.g. more space to put an additional circuit breaker and GIS on a large island and enable a new interconnector).</td><td>Since Distributed Concept is limited in size to a few GWs, it is likely that it will feature steel platforms or caissons as preferred support structure types. Steel platforms and caissons are designed in a lean way, often with the goal of minimising the material costs, hence not leaving any extra space beyond what is strictly needed for a safe operation. Expanding such a hub can be very costly, if the expansion is not foreseen upfront (e.g. not enough space for additional cable j-tubes or gas pipe terminals).</td></tr>
<tr><td>Gas infrastructure</td><td>No gas infrastructure required. Relatively "simple", purely electrical design of offshore hubs facilitates modularity.</td><td colspan="3">With offshore hydrogen production, the hubs will need to host both electrical and gas infrastructure. Although this is technically feasible, such hubs are more complex in their design and implementation, which makes them less modular, compared to a purely electrical or purely gas hubs. Additional interfaces and components may lead to difficulties when expanding.</td></tr>
</table>

Table 3-7 Modularity assessment

Based on the above assessment, DNV notes that both Centralised and Distributed concepts have their own merits in terms of modularity. The Centralised concept offers flexibility to expand and larger space margins for new interfaces and design change, once the infrastructure is built. The Distributed Concept, on the other hand, is characterised by smaller blocks, which minimises the development risks and the volume of anticipatory investment and allow to cope better with policy and regulatory uncertainty by delivering infrastructure in smaller steps, closely following the generation roll-out.
The parameters of distributed small hubs (location, size, time of construction, rating, equipment characteristics) can be adjusted at any stage of development towards 2050, unlike those of the Centralised concepts. Finally, when comparing offshore with onshore hydrogen production, it is observed that onshore hydrogen production makes offshore infrastructure design less complex, focusing on electrical system design only. Modifications or expansions will likely be more difficult to realise where multi-commodity infrastructure is integrated on the same hub.

3.7 Requirements for onshore reinforcements

Integrating 36 GW of offshore wind into the onshore power system will inevitably require onshore reinforcements of some scale. These reinforcements will be needed to bring power from the points of connection further to the main transmission corridors, and eventually to the demand centres. The exact number of onshore substations and overhead lines will vary depending on the selected concept. A detailed power system modelling would be required to identify the exact needs to accommodate potential thermal overloads on the circuits based on the onshore network configuration and the power flow injections from the offshore. Still, it is possible to comment on a high level on the relative differences between the concepts.

Seeing that the total transmission capacity connected to a certain country is the same for all concepts, we can ignore the aggregated impact of the power injection magnitude that needs to be accommodated by the respective national networks – this will be the same across the four concepts. In contrast the distribution of this total capacity and the energy carrier with which it is delivered varies, and hence will be in the focus of our consideration.

Firstly, comparing onshore with offshore hydrogen, DNV expects that offshore hydrogen production will allow to reduce the number of onshore HVDC converter stations by a factor roughly equal to the total capacity of offshore electrolysers divided by 2 (assuming 2 GW HVDC converters as a standard). Within this study the total number has been reduced from 21 in Concept 1 (onshore hydrogen) to 15 in Concepts 2 and 3, and 14 in Concept 4 (all – offshore hydrogen production). Consequently, the number of overhead lines will be reduced accordingly as it won't be required to connect those substations to a wider onshore power network. If onshore electrolysers are located at coast and powered directly from the offshore wind (so-called onshore co-location of hydrogen and offshore wind), the construction of overhead lines in the coastal area could be avoided, but this would still require HVDC converters to convert offshore power from high voltage DC to AC and to bring voltage down to a level that can be used for electrolysis. Obviously, the vast amounts of produced hydrogen, whether offshore (Concepts 2-4) or from onshore coastal electrolysers (Concept 1) will require a hydrogen infrastructure to transport it to the offtake centres, regardless of whether it is produced onshore or offshore.

Considering the other dimension of Centralised against Distributed concept, one point of view is that the Distributed results in a higher number of offshore landing points than Centralised (12 versus 9 based on the count of connections hub-to-onshore in Figure 2-7 and Figure 2-10). This assumes that where multiple cable circuits and or pipelines connect a hub to shore, they will be routed through the same trench on the seabed, hence arriving to shore at the same location*. However, what matters for the onshore reinforcement volume is the number of connection points – HVDC converters for electrical, and gas interconnection terminals for hydrogen transmission. In our designs, Distributed leads to a minor difference in the number of connection points, as we defined them in section 3.5, (22 versus 21). DNV believes that the latter is an impact of concrete implementation rather than a broader concept, hence we do not conclude on the impact of Distributed against Centralised from this perspective.

The assumption of routing multiple cable circuits and or pipelines through the same trench on the seabed, brings us to the final consideration. Comparing Centralised and Distributed concepts, we note that ceteris paribus the level of power injection in a network around a single landing point is higher in the Centralised concepts, e.g. 17 GW to Denmark are allocated among 3 landing areas in Centralised versus 5 in Distributed. Higher power injections or concentration of infeed at a network around a single landing area raise security issues, hence additional reinforcements in the grid might be required in Centralised to accommodate those. Onshore hydrogen production is one factor that allows to alleviate this issue partly, as certain share of power brought to shore can be directly injected into onshore electrolysers. Hence, the need for power network reinforcements reduces at the cost of additional electrolysis and gas transportation infrastructure.

* Arguably, this assumption implies that minimising the cost of underwater operations and environmental impact on the seabed (routing through the same or parallel trenches) is preferred over distributing power from large hubs to multiple landing points (multiple routes to different points of connection).

3.8 Regulatory complexity

This section elaborates the various regulatory and market aspects related to the development of integrated offshore network. DNV will consider the status of regulatory and market frameworks as of today, in such a way indicating where developments need to take place to enable the proposed concepts, focusing on those aspects that are different depending on the chosen concept. We recognise that there are multiple other regulatory areas that will have to evolve, but if the issue is equally relevant for all concepts, we will not comment on it.

Support structure

Coastal states are allowed to develop artificial islands as well as installations and structures for the purpose of the economic exploitation of the sea. A newly created sand island will be considered as an artificial island, whereas a platform or caisson island are considered to be an 'installation'. The environmental impact of an artificial island, which is likely to be featured in the Centralised concepts 1 to 3, will be much larger than a platform in Distributed concept, especially during construction period. Hence, this should be analysed when selecting a certain type of support structure. While there is a removal obligation for installations and structures (including platforms and caisson islands) when they are no longer used, it is not required for artificial islands. Another gap in the current regulation is related to the applicability of national law depending on the support structure type. While for installation the regulatory framework has been established, it is not yet so well defined for artificial islands. For example, when an infrastructure is developed on an artificial island, it is not yet defined whether the relevant onshore permits apply, or those for activities at sea.

Permitting

Considering permitting, the larger the environmental impact, the more difficult the permitting procedure will be. In case of large artificial islands, as in Centralised concepts 1 to 3, the entire offshore hub will have to be permitted at once, which may lead to significant delays and public opposition. When the interests of groups such as fisheries and nature conservation NGOs are not taken along in the decision-making process, the risk of public unrest increases. This is not the case for Distributed concept, where hubs are smaller and easier to obtain permits for. In Centralised Concept, obtaining the permits is particularly difficult because the large hubs will be expanded in a course of a period of many years, as the wind generation capacity connected to them grows. This long-duration expansion creates additional uncertainties which have to be accounted for in the permitting phase. Additional layer of complexity in terms of permitting is brought by offshore hydrogen production which will require additional permits in Concepts 2 to 4.

Treatment of offshore hydrogen

For Concepts 2 to 4, where hydrogen is produced offshore, the governance and ownership of hydrogen infrastructure need to be considered. It is currently uncertain whether a TSO may own and operate the production infrastructure, or it must be operated by a third party. For example, an electrolyser can be considered as part of the gas infrastructure, but (at least under the current legal framework) the Gas Directive is only applicable when the produced hydrogen is fed into the (onshore) gas transmission system. Alternatively, the infrastructure can also be considered to be a form of electricity storage, thus falling under the legal framework for electricity rather than gas. Reconversion into electricity is not necessary for this. Similarly with gas pipeline, an open issue is whether a hydrogen pipeline from a hub to shore is considered an upstream pipeline or part of a hydrogen transmission system. Upstream pipelines can be owned and operated by private companies. In addition, upstream pipelines are not regulated, they are financed by private companies. If the pipeline is considered as a part of regulated asset base (RAB), it will have to be financed by the grid tariffs, in a regulated way.

Anticipatory investment framework

Construction of large offshore support structures in Concept 1 to 3 will require anticipatory investment as those assets are likely to be built several years ahead of the moment when full generation capacity for which a hub is constructed gets built. It is not clear which stakeholder type will be willing to commit the required investment. At the moment it is rather unlikely that private parties will agree to the development of e.g. 10 GW offshore island, if only 2-4 GWs of wind generation are deployed in the first years of its operation. Government would need to introduce additional incentives or support schemes to drive such an investment by private market parties. Alternatively, this could be positioned within TSO's remit. At present, TSOs recover their investments via regulated tariffs, whereby a national regulatory authority (NRA) monitors and assesses the necessity and efficiency of those investments when approving the TSO's costs. It is yet to be determined whether anticipatory investments will be treated as efficient costs by the regulator. As such, DNV is of an opinion that the deployment of smaller hubs such as those in Concept 4 will be less complex than for the Centralised concepts considering the investment and financing.

	CONCEPT 1 Centralized - H2 onshore	CONCEPT 2 Centralized - H2 offshore - combined electricity and H2	CONCEPT 3 Centralized - H2 offshore - dedicated OWF's for hydrogen production	CONCEPT 4 Distributed - H2 offshore - combined electricity and H2
Support structure	Higher environmental impact to be investigated via EIA and lack of clarity on the applicability of onshore regulatory frameworks on artificial islands.			
Permitting	Potential delays due to complicated permitting procedures for artificial islands and large support structures at sea. Uncertainty about which expansions and future development need to be accounted for in the permitting phase.			
Treatment of offshore hydrogen		Uncertainty about the legal classification of hydrogen production at sea. Potentially, uncertainty about ownership and governance for large scale offshore hydrogen production.		
Anticipatory investment framework	Requirements for anticipatory investment in large support structures require alternative financing and support mechanisms to attract the capital. Optionally, TSOs could be made responsible for financing of strategically important energy infrastructure which would require revision of their cost recovery models.			

Table 3-8 Regulatory complexity per concept

In Table 3-8 we indicate with orange colours areas where regulatory barriers exist at present and would have to be resolved for a particular Concept.

DNV concludes that the current regulations do not favour Centralised concepts based on large offshore hubs, several barriers would have to be surmounted to make them feasible. Similarly, regulatory basis for offshore hydrogen production at the moment is considered to be immature. DNV expects development in both areas as strong government and policy ambitions drive the progress. With this discussion we have highlighted the gaps that are relevant for 2022.

3.9 Summary of the assessment

Figure 3-11 provides an illustrative overview of results for all KPIs. In this diagram, the further from the centre is a line, the better the concept represented by this line scores against a given KPI. Concept 1: Centralised – Hydrogen onshore is used as a counterfactual, meaning that it scores 1 on all KPIs and other concepts are benchmarked to it. Note, that no weighting has been applied to the KPIs. The absolute distance to the centre should not be compared between the KPIs, since they are expressed in different units and some of them are qualitative. For the latter ones, we have assigned a mark based on the number of aspects which performed worse or better compared to the counterfactual. Such a representation, although being indicative, allows to capture all the differences between the concepts in a single graphics.

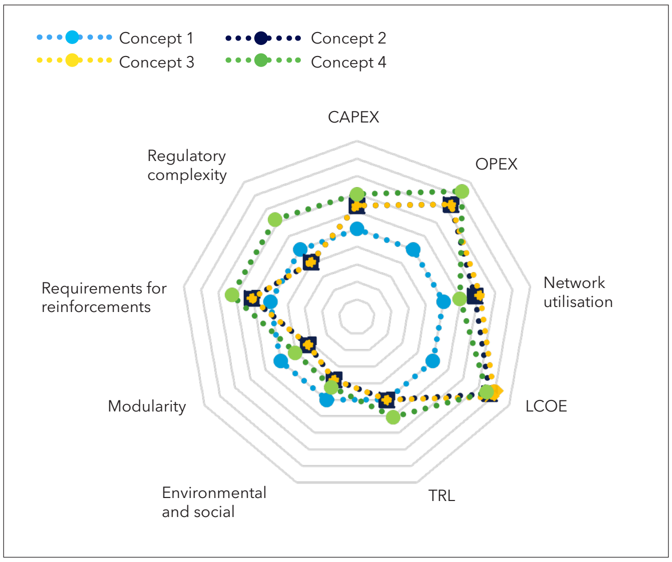


Figure 3-11 KPI summary

As a result of our analysis it is evident that Distributed – Hydrogen offshore – Combined Hydrogen and Electricity concept scores best in CAPEX, OPEX, TRL, requirements for onshore reinforcements and regulatory complexity. This is mainly achieved due to the reduced hub size and offshore production of hydrogen. In contrast, it performs worse than the basic Centralised – Hydrogen onshore when it comes to modularity and environmental and social impacts.

Centralised concepts with offshore hydrogen production are a favourable option when it comes to minimising costs and requirements for the reinforcements. These concepts may turn to be less advantageous, however, if regulatory complexity, modularity or environmental and social impacts are considered. The counterfactual Centralised – Hydrogen onshore concept, according to our analysis, is sub-optimal when it comes to costs and onshore reinforcement minimisation, although it does prove to be a good option when modularity and environmental and social impacts are considered.

The concepts selected in this analysis were intended to be different enough to be able to reflect how widely opposite decisions on certain aspects affect the performance against a certain KPI. It is possible that an optimal solution lies somewhere between the extremes that were chosen on each of the dimensions, and as such combines best features of the four concepts considered in our investigation. To support the decision makers, in what follows DNV provides a short summary of which concept features may allow to gain an advantage across each of the KPIs.

CAPEX and OPEX – our evaluation indicates that Distributed hubs allow to save on the cost of cables and pipelines, which although partially compensated by more expensive support structures, does result in overall lower cost than the Centralised solutions.

TRL – based on the present state-of-the-art power and gas transmission technology, we observe that the Distributed concept may be more favourable as it features smaller components in relatively simple internal hub network topologies. Offshore hydrogen, currently considered to be immature, poses another technical challenge. DNV expects significant technological progress against all the technical areas analysed in this assignment, hence the above conclusion only concerns the present state and flags the need for development and progress in certain domains.

Power network utilisation – Concept 3 has the best overall utilisation, mainly as an outcome of the highest generation with the lowest curtailment levels. The main reason is that in this concept part of the generated electricity is used solely for hydrogen production, even in the moments when electricity price is high, and thus does not have to take issues related to the surrounding power system into account. Concept 1, with hydrogen production located onshore suffers from frequent curtailment and leads to the lowest asset utilisation.

LCOE – all three concepts with offshore hydrogen production are characterised by a significantly lower LCOE than the one with the onshore hydrogen. DNV highlights that LCOE metric portrays larger differences between the concepts than CAPEX and OPEX assessment. The underlying reason is that in addition to somewhat lower overall costs, offshore electrolysis facilitates improved assets utilisation and lower curtailment of offshore generation. Centralised concept with dedicated wind farms for offshore hydrogen production (Concept 3) allows to achieve the lowest LCOE, although the difference with the combined electrical and gas connection in Centralised (Concept 2) and Distributed (Concept 4) hub setup is marginal. Therefore, DNV concludes that for the minimisation of the LCOE location of the hydrogen production is the dominant factor.

Environmental and social impacts – offshore hydrogen production is likely to lead to additional subsea works on laying the pipelines (or adapting the existing ones to hydrogen transmission). This is expected to increase negative environmental impacts, compared to purely electrical solutions, whereby multiple cable circuits can be deployed underwater in a single cable-laying campaign. The total length of subsea trenches can be minimised if only electrical infrastructure needs to be deployed. Distributed concept provides some advantage in reducing the length of cables and pipelines thanks to an ability to better optimise hub locations, which in its turn leads to reduced environmental impacts. All concepts seem to lead to a similar number of onshore landing points, hence impact on the local communities in the coastal areas due to construction phase and or negative consequences for the visual amenity are barely affected by the choice of Distributed against Centralised, or Onshore against Offshore hydrogen production.

Modularity – Distributed approach is favourable as it allows to break down the entire infrastructure network into a number of smaller projects, which can be planned, designed and implemented in parallel with the deployment of offshore wind generation capacities. This, compared to the Centralised approach, minimises the necessity for the anticipatory investment and reduces the risk of stranded assets. Yet, Centralised concepts gain points on modularity since they have inherently more space for potential expansions in the future. For instance, adding another interface to connect a new power link can be easier on a larger hub featuring sand- or caisson island as its support structure than on a steel platform, likely to be used for smaller Distributed hubs. Offshore hydrogen is likely to make modular expansion of offshore hubs more complicated due to the overall increase in the complexity of hub system design.

Requirements for onshore reinforcements – offshore hydrogen production leads to significant reductions in the requirements for onshore reinforcements needed to integrate the vast amount of offshore wind energy into the onshore system. By converting part of the generated energy to hydrogen offshore, the number of HVDC converters onshore, as well as the overhead lines linking the points of connection to a wider onshore network, can be reduced notably. Whilst, integrating the generated energy in the form of hydrogen will lead to reinforcements of the gas system, DNV expects that the scale will be much lower as compared to the reinforcement of the power system required to accommodate the same volumes of energy. Furthermore, development of the offshore infrastructure in a Distributed manner may prove to be another way to reduce the demand for onshore reinforcements. Distributed concepts are expected to lead to a higher number of landing points, hence distributing power injection among multiple onshore network regions, unlike in the Centralised case, where bulk power is brought to the same location onshore.

Regulatory complexity – Distributed approach to offshore hub development, based on the current state of legal and regulatory framework would face the least difficulties in the planning, development and operational phase. Smaller offshore hubs, featuring platforms rather than artificial islands, are currently better regulated. Obtaining permits, as well as financing and governance will be more straightforward for small offshore hubs. Large offshore hubs, such as those in the Centralised concepts, increase deliverability risks and require additional support mechanism from government to ensure sufficient capital is attracted in a form of anticipatory investment. Concepts with Hydrogen offshore would be impeded by the uncertainty about the legal classification of hydrogen production at sea. Lack of clarity about ownership and governance for large scale offshore hydrogen production would be another barrier. As with the TRL assessment, the above issues will possibly get resolved in the coming years, hence with the above conclusions DNV represents the today’s situation and provides an indication of areas where progress is needed.

4. CONCLUSIONS AND RECOMMENDATIONS

4. CONCLUSIONS AND RECOMMENDATIONS

4.1 Conclusions

DNV has analysed four different offshore infrastructure concepts which vary in the size and number of offshore hubs, location of hydrogen production and way of connecting electrolysers to windfarms. The concepts are designed to allow the integration of 36 GW of offshore wind located in the Danish EEZ into the onshore network of North Sea countries in 2050. Within the study we have assessed these concepts against a number of KPIs. Whilst our investigation did not aim to indicate an absolute winner among the analysed concepts, it did highlight a number of observations with regards to the relative performance against each of the considered KPIs.

DNV concludes that there is not one single concept that outperforms the others in every single considered KPI. Both Distributed and Centralised concepts have advantages. Distributed Concept brings higher flexibility as it allows to locate hubs more optimally with respect to the offshore wind lease areas and points of onshore connection and takes advantage of this location to minimise the cost. Though, it highly depends on the parks not being taken earlier. On the other hand, the Centralised Concepts take advantage of economies of scale by building artificial islands of 8-10 GW as some studies suggests that large scale islands can come at a significantly lower cost. The sensitivities exploring the impact of an optimised detailed design concepts and a more optimistic view on cost of offshore islands bring the cost difference between Decentralised and Centralised Concepts to negligible level considering the conceptual nature of this study. Onshore hydrogen production is likely to be more expensive than offshore, regardless of whether the offshore electrolysers are coupled to a wider power network or powered directly from dedicated individual windfarms. Whilst offshore electrolysers are expected to be more expensive than their onshore counterparts, the savings from avoiding the need to build some of the HVDC converters are of a much larger scale. For example, the difference between Concept 1 and 2 is around 6%. This conclusion holds even if the costs of the offshore electrolysis are by 20% more expensive than that of the onshore.

The concepts exhibit some minor differences in how the infrastructure is utilised. Namely, concepts with offshore hydrogen production have better overall utilisation, mainly as an outcome of lower curtailment levels. In moments when electricity price is low and there is oversupply in the system, it is possible to produce hydrogen offshore, thereby neglecting onshore constraints. Concept 1, with hydrogen production located onshore suffers from frequent curtailment caused by the inability of the onshore network to absorb more power from the offshore and leads to the lowest asset utilisation. Note that we assume onshore electrolysers to be connected to the transmission grid, not behind-the-meter at the coast.

As a summary of costs and utilisation, we have also evaluated the LCOE. Centralised concept with offshore hydrogen generation from dedicated wind farm resulted in the lowest LCOE across all. Although, the differences with the combined electrical and gas connection in Centralised (Concept 2) and Distributed (Concept 4) hub setup are marginal. Meanwhile, the onshore hydrogen production in the Centralised concept led to a much higher LCOE. Hence, we conclude the location of hydrogen production to be a dominant factor, with hub size and number as well as connectivity of offshore electrolysers to have negligible effect on LCOE.

DNV has considered the technological maturity of the infrastructure concepts based on the present state-of-the-art power and gas transmission technology. Distributed concept may be more favourable as it features smaller components in relatively simple internal hub network topologies. Offshore hydrogen, currently considered to be immature, poses significant technical challenge.

Our analysis has considered what impacts the different infrastructure concepts will have on the marine and coastal environment and social communities in the coastal areas. Distributed hub development allows for reducing the length of cables and pipelines by better optimising hub locations, which leads to reduced environmental impacts offshore. All concepts seem to lead to a similar number of onshore landing points, hence the magnitude of impacts on the communities in the coastal areas are barely affected by the choice of Distributed against Centralised, or Onshore against Offshore hydrogen production.

Distributed approach might be favourable as it allows to break down the entire infrastructure network into a number of smaller projects, which can be planned, designed and implemented in parallel with the deployment of offshore wind generation capacities. This, compared to the Centralised approach, minimises the necessity for the anticipatory investment and reduces the risk of stranded assets. Yet, Centralised concepts gain points on modularity since they have inherently more space for potential expansions in the future. Offshore hydrogen is likely to make modular expansion of offshore hubs more complicated due to the overall increase in the complexity of hub system design as an inherent feature of integrating electrical and hydrogen equipment.

We found that offshore hydrogen production leads to likely reductions in the requirements for onshore reinforcements needed to integrate the vast amount of offshore wind energy into the onshore system. By converting part of the generated energy to hydrogen offshore, the number of HVDC converters onshore, as well as the overhead lines linking the points of connection to a wider onshore network, can be reduced notably. Furthermore, development of the offshore infrastructure in a Distributed manner may be another way to reduce the demand for onshore reinforcements. Distributed concepts are expected to lead to a higher number of landing points, hence distributing power injection among multiple onshore network regions, unlike in the Centralised case, where bulk power is brought to the same location onshore.

Finally, we have considered the regulatory complexity. In this context, Distributed approach to offshore hub development, based on the current state of legal and regulatory framework would face the least difficulties in the planning, development and operational phase. Smaller offshore hubs, featuring platforms rather than artificial islands, are currently better regulated. Obtaining permits, as well as financing and governance will be more straightforward for small offshore hubs. Concepts with Hydrogen offshore would be impeded by the uncertainty about the legal classification of hydrogen production at sea. Lack of clarity about ownership and governance for large scale offshore hydrogen production would be another barrier.

We note that both for the technology readiness level and regulatory complexity, DNV expects that the highlighted issues will get resolved in the coming years. Hence, our conclusions in these areas only concern the present state and indicate the need for development and progress in certain domains.

4.2 Limitations of the study

Our investigation is inherently conceptual in its nature – the objective was to compare the potential offshore infrastructure concepts in their 2050 state. These concepts should allow to integrate up to 36 GW of offshore wind in the Danish EEZ, the scale that is much higher than the current ambitions. This value is also significantly exceeding the expected demand for power in Denmark, thus inevitably large part of this capacity will have to connect to other North Sea countries.

Within this context, DNV has defined high-level conceptual infrastructure options that reflect major choices that the decision makers will face. These include location of hydrogen production, size and number of offshore hubs and connectivity of gas and power assets within a hub. There are more choices to be made, for example with regard to the level of onshore integration, i.e. how deep inland the offshore infrastructure gets connected with the onshore network.

Whilst limiting the scope of the study to a small number of dimensions allowed to reach certain insights about the outcomes of choices and compare the proposed concepts, the absolute values obtained within this study have little value. A number of practical assumptions were made with regard to the hub locations, their size and onshore points of connection. The network capacity was not optimised either, which could allow to reduce costs and increase utilisation. DNV highlights that the focus of the study was on the comparative analysis, indicating relative performance of the considered concepts. The absolute costs, LCOE, utilisation rate and other KPIs should be treated as indicative only, as further changes will come out as a result of the detailed design phase of such projects.

Our concepts have not considered the emerging wind-to-hydrogen turbines, whereby small-scale electrolysers are located within the wind turbine.

Note that we deliberately exclude radial* concept from the consideration, since multiple studies have proven it to be sub-optimal for large quantities far offshore in the long term**.

This concept does not allow to achieve economies of scale and capitalise on the lower unit cost of HVDC equipment utilised for far offshore wind farms.

Our cost assessment did not consider the intertemporal development of the proposed concepts, but rather looked at the snapshot of their state in 2050. It is fair to expect that Centralised concepts will require higher level of anticipatory investment, hence part of the cashflow will be moved earlier in time. In the detailed NPV analysis, this would favour Distributed approach to hub development as some of the investment would occur later in the future and be subject to a higher discounting factor.

The extent of power flow modelling was limited to capture the network utilisation but it did not include detailed dispatch analysis or power system constraints. This has limited the depth of our assessment, whereby only costs have been monetised, while socio-economic benefits were deliberately left out of scope. We are aware that DEA is planning a more detailed study of these aspects. At the same time detailed power system modelling would reveal additional insights on the requirements for onshore reinforcements, which we were only able to assess qualitatively based on our engineering judgement.

Our technology choice was conservatively based on the 2022 state-of-the-art technology availability for the power equipment, on the one hand. On the other hand, for hydrogen our assumptions include technical feasibility of offshore production at GW scale, which has not been realised so far.

Even though, DNV is of an opinion that all of the proposed concepts are technically feasible and can be delivered by 2050, it is uncertain which exact technologies or system design will be used. This might have impact on the cost and operational characteristics of each concept.

A number of KPIs, such as environmental and social impacts, modularity, regulatory complexity and requirements for onshore reinforcement were valued qualitatively based on the DNV's expertise gained in similar studies. For instance, our environmental impact assessment utilised asset count as a proxy for the magnitude of negative impacts on marine environment and coastal areas. A more detailed study in the planning phase may reveal additional aspects which were not captured in this analysis. Our regulatory complexity overview considered a limited number of outstanding barriers or gaps in today's regulation. We note that there might be more issues in detailed permitting law and other secondary regulation. In contrast, some of the issues that we flagged will likely get resolved by 2050 if Europe is to reach its ambitious targets in offshore wind deployment in the North Sea.

4.3 Recommended follow up work

Having conducted this initial conceptual study, we recommend the following follow-up work to better capture and understand the differences between the potential offshore infrastructure concepts:

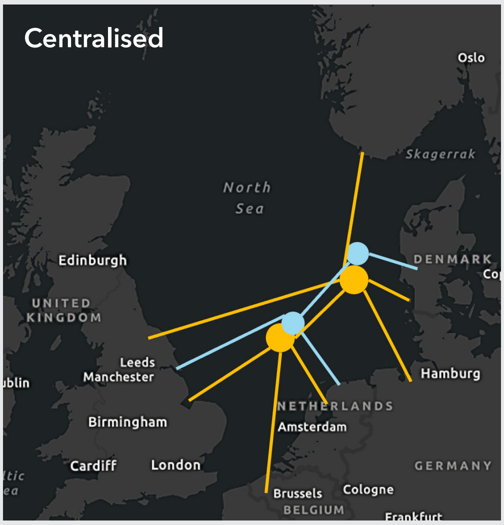
- Next level of detail design of the offshore infrastructure, including the temporal dimension of when assets are built. This will allow to better capture the necessary technologies, their costs and evolution of each concept in time.
- Detailed cost benefit analysis, including elaborated market modelling, potentially at zonal or nodal level for the countries that get connected. This should explore aspects such as CO2 emission level, curtailment, congestion rents and generation cost in the connected countries.
- Detailed power system analysis, including power flow injection in the onshore points and identification of onshore reinforcements required to integrate 26 GW of offshore wind into the system and deal with potential network constraints.
- Optimisation of hydrogen capacity per hub based on the hydrogen demand, electricity prices, costs of equipment and wind resource.
- Detailed analysis of applicable regulation in the Danish EEZ and connected countries, including permitting procedures.
- Detailed study of landing points and connection points.

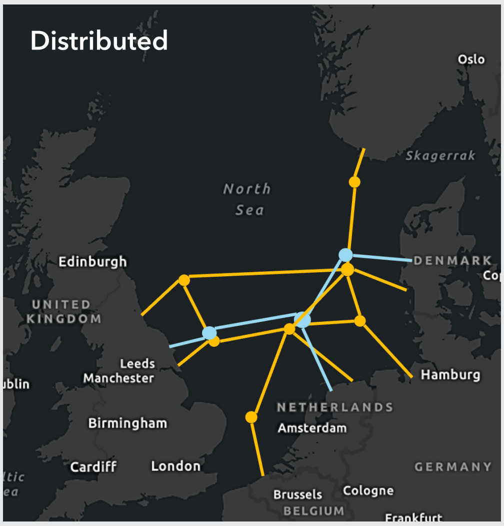
* A radial connection is a point-to-point connection
** Studies such as PROMOTioN; the Offshore Coordination Project set up by the NGESO, and Study of the benefits of a meshed offshore grid in Northern Seas region by TE, ECOFYS and PwC for DG ENER, just to mention some

APPENDIX A
Concept dimensions illustrations

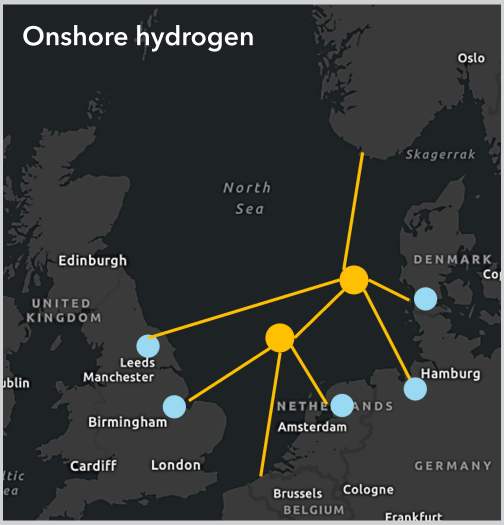
APPENDIX A
Concept dimensions illustrations

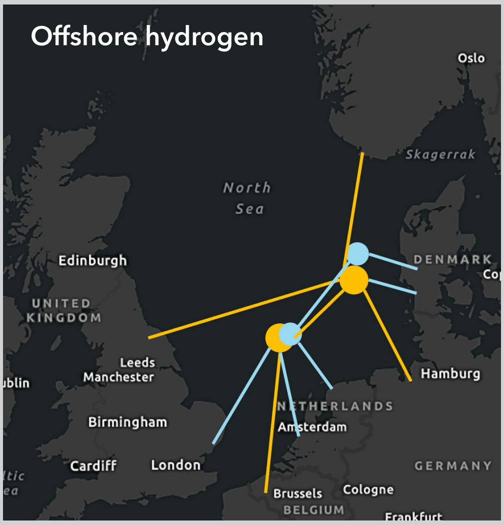
DIMENSION 1 - Network concentration



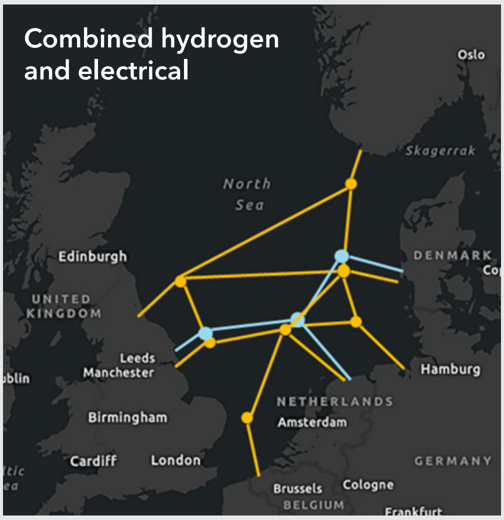


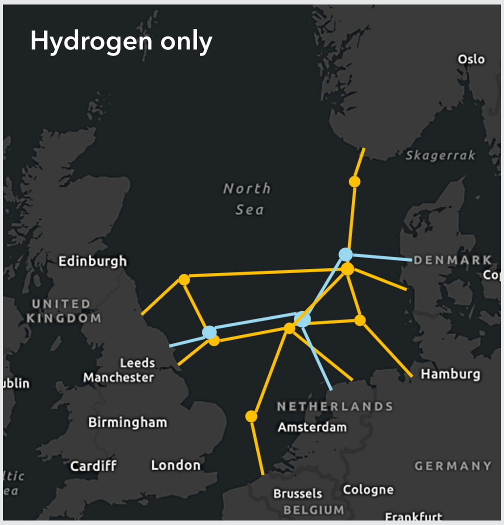
DIMENSION 4 - Hydrogen location





DIMENSION 5 - Dedicated hydrogen OWF's





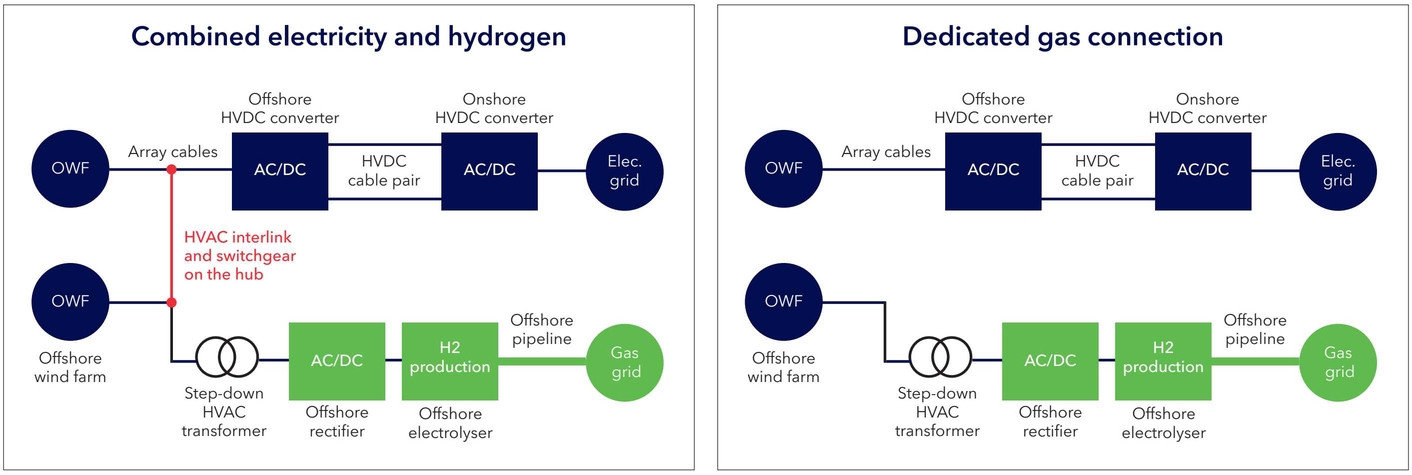


Figure A-1 Sample hub single line diagram

APPENDIX B
DNV’s European power market model

APPENDIX B
DNV's European power market model

DNV has extensive experience in power market modelling (20+ years), including the use of scenario analysis and impact on overall system cost, power price, system reliability, balancing needs and system capabilities.

DNV is using PLEXOS® Integrated Energy Modelling software, an industry state-of-art power market and transmission network modelling framework developed by Energy Exemplar (http://energyexemplar.com). DNV is among the most sophisticated users of PLEXOS® and is using PLEXOS® for power market and dispatch modelling, herewith using a bidding zone representation of the power system in Europe.

Our European Power Market model is a fundamental market model that simulates the day-ahead spot price by optimizing the unit commitment and economic dispatch of electricity generation to enable a broad range of technical and commercial analysis. It is a flexible model, allowing different topologies and levels of detail. It is assumed that generators price their generation based on their short-run-marginal-costs.

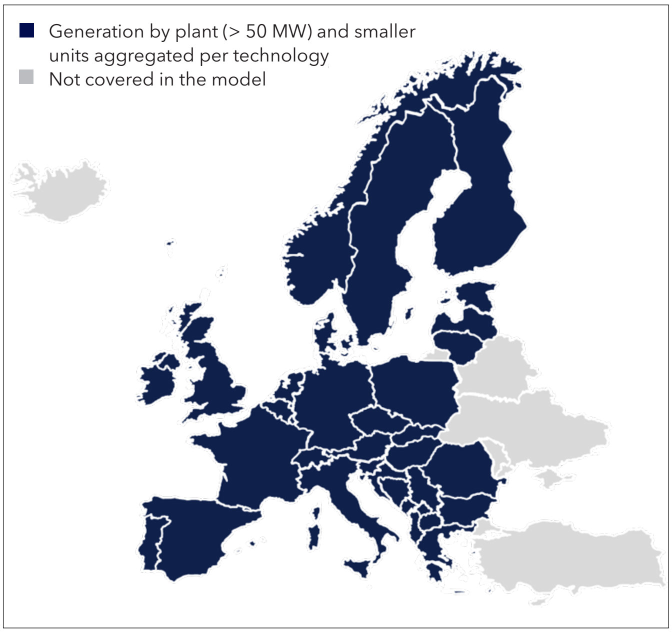
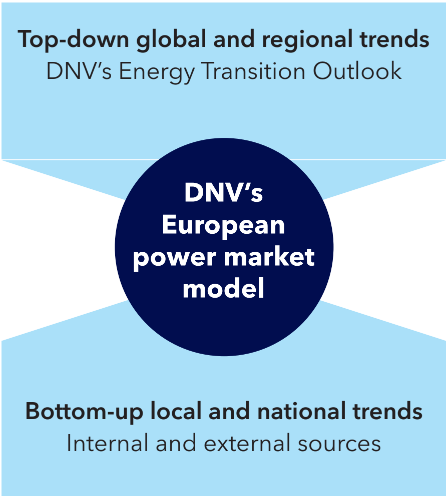


Figure B-1 Countries modelled in DNV's power market model

The simulations are performed on an hourly time-resolution containing a detailed representation of generation, commodity prices and demand for all bidding zones in Europe, including the envisioned developments:

- Generation capacities are modelled on an individual basis with detailed techno-economic characteristics, such as but not limited to: heat rates, ramping ability, minimum stable level, fuel cost, other variable operating costs, maintenance and forced outage rates, etc.
- Renewable generation takes volatility into account through the use of historical or re-analysed time-series of e.g. wind-speed and solar-irradiation data for different locations. These profiles take the geographical correlation into account.
- Market exchanges between countries (i.e. bidding zones) are defined based on net-transfer-capacities. The increase in available transmission capacity is based on available projections announced by individual TSOs and/or ENTSO-E.
- The demand consists of an hourly fixed demand profile and flexible demand components coming from electrification of mobility, heating, and power-to-x.

DNV's 'Most Likely Future' Power Market Forecast is based on DNV's vision on the long-term regional development of the global energy system until 2050 as provided in the Energy Transition Outlook (ETO). This top-down global and regional development, as detailed in the ETO, is complemented and consolidated with bottom-up insights from internal and external sources to develop the scenario on a country-level basis for implementation in the DNV's European power market model. This market model is then used to obtain the results (Figure B-2 and Figure B-3).



1. TOP-DOWN TRENDS
The ETO includes global and regional findings and trends based on developments of economic growth, population, technology learning curves and global energy intensity, resulting in assumptions on a European level:
- Commodity price trends
- Demand developments
- Generation mix developments on a European level

2. BOTTOM-UP TRENDS
This top-down global and regional development is complemented and consolidated with bottom-up insights from internal and external sources to develop the scenario on a country level basis for implementation in the DNV's European power market model:
- Country's net-zero targets
- Country's policies
- Country's develpment plans

3. EUROPEAN MODEL
The European power market model with information about core countries in then used to obtain the results.

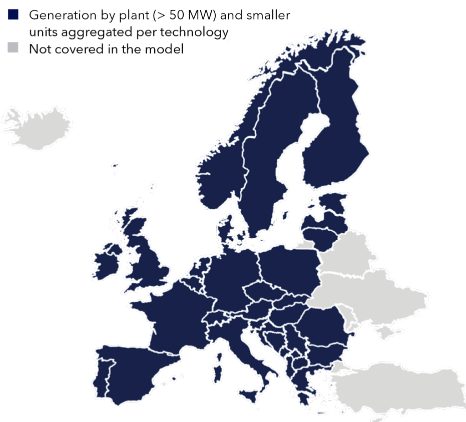
Figure B-2 DNV's power market model methodology

ASSUMPTIONS

DNV's vision of the most likely future quantified per country:

- Existing generation structure
- Developments in generation assets
- Generation unit characteristics
- Hourly variable renewable profiles
- Fuel and CO_2 price trends
- Network constraints
- Electricity demand profiles
- Flexibility (batteries, EVs, DSM, P2H)

EUROPEAN POWER MARKET MODEL IN PLEXOS



RESULTS

- Spot power price development (monthly average prices)
- Generation weighted price per asset class (monthly average prices)
- Generation mix for the selected country (like share wind, solar, hydro, coal, nuclear)
- Understanding and background of the market developments
- Insight in the top market drivers and sensitivities
- Market dynamics with connected countries, i.e. monthly import/export position
- Transparency on the used assumptions behind the forecast

Figure B-3 Assumptions and results

APPENDIX C
Detailed concepts

APPENDIX C
Detailed concepts

The hub placements and cable lengths have not been optimised. This limits comparability between concepts, especially comparing Concept 4 to other concepts.

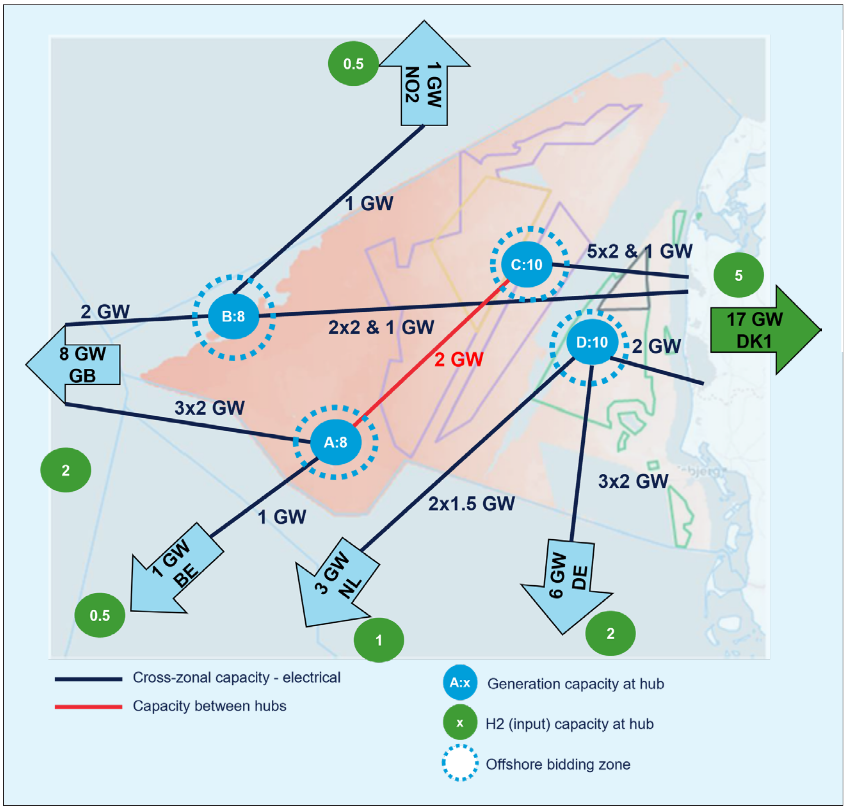
Cables A_GB	380
Cables A_BE	481
Cables A_C	136
Cables B_GB	365
Cables B_NO	332
Cables B_DK	235
Cables C_DK	76
Cables D_DK	66
Cables D_DE	277
Cables D_NL	298

Table C-1 Assumed cable and pipeline length in Centralized concepts (km)

	CONCEPT 1	CONCEPT 2	CONCEPT 3	CONCEPT 4
Cables 2 GW	3,388	2,877	2,877	2,542
Cables 1.5 GW	596	0	0	0
Cables 1 GW	1,124	0	0	0
Cables 0.5 GW	0	813	813	795
Pipeline 0.4 GW	0	813	813	795
Pipeline 0.8 GW	0	533	533	332
Pipeline 1.6 GW	0	657	657	804
Pipeline 3.2 GW	0	76	76	0

Table C-2 Comparison of total cable length and pipeline length per capacity level (km)

CONCEPT 1 - Centralized - Hydrogen onshore



	DK1	DE	NL	BE	GB	NO2	A	B	C	D	SUM TO SHORE
A				1	3x2				2		7*
B	2x2 1				2	1					8
C	5x2 1						2				10
D	2**	3x2	2x1.5								11**
SUM	17+1**	6	3	1	8	1					36

*1 GW of installed capacity from A flows to DK via C
**extra 1 GW to DK to facilitate trade on DK-DE and DK-NL directions

Table C-3 Line capacities in 'Centralized - Hydrogen onshore' concept

CONCEPT 2 & 3 - Centralised - Hydrogen offshore

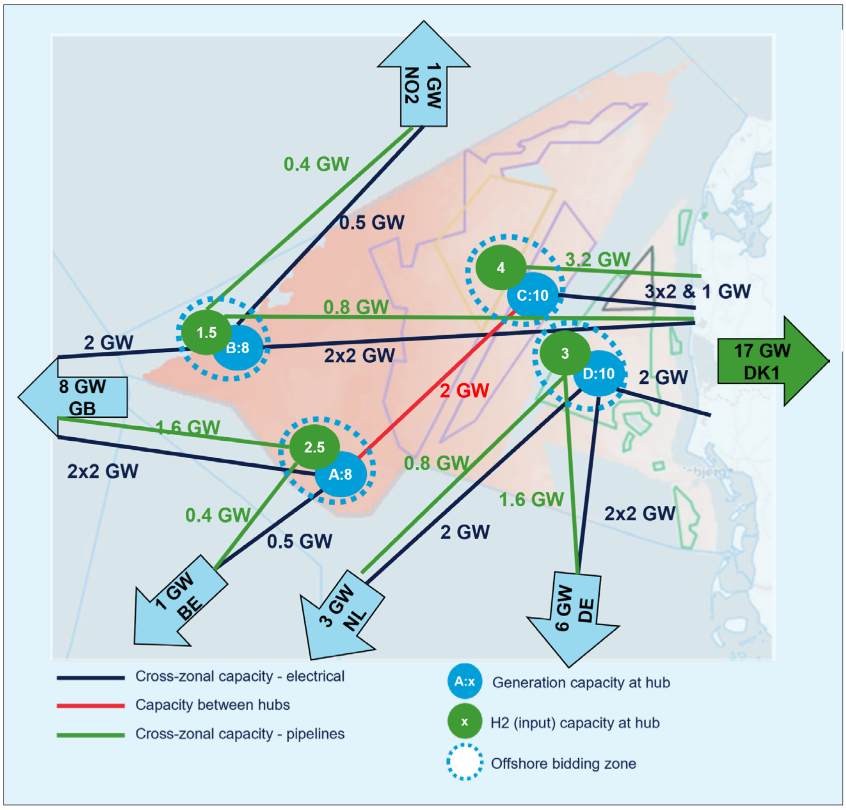


Table C-4 contains the underlying data on the capacity of connection, where power connections are marked with blue colour.

	DK1	DE	NL	BE	GB	NO2	A	B	C	D	SUM TO SHORE
A				0.5 0.4	2x2 1.6				2		4.5 2*
B	2x2 0.8				2	0.5 0.4					6.5 1.2
C	3x2 1 3.2						2				6 1 3.2
D	2**	2x2 1.6	2 0.8								8** 2.4
SUM	12+1** 4	4 1.6	2 0.8	0.5 0.4	6 1.6	0.5 0.4					26 8.8

*1 GW of installed capacity from A flows to DK via C
**extra 1 GW to DK to facilitate trade on DK-DE and DK-NL directions

Table C-4 Line capacities in 'Centralised - Hydrogen offshore - Combined Hydrogen and Electrical' concept

The distribution of hydrogen production among hubs is given in Table C-5.

Hub	H2 on a hub (input GW)
A	2.5
B	1.5
C	4
D	3
TOTAL	11

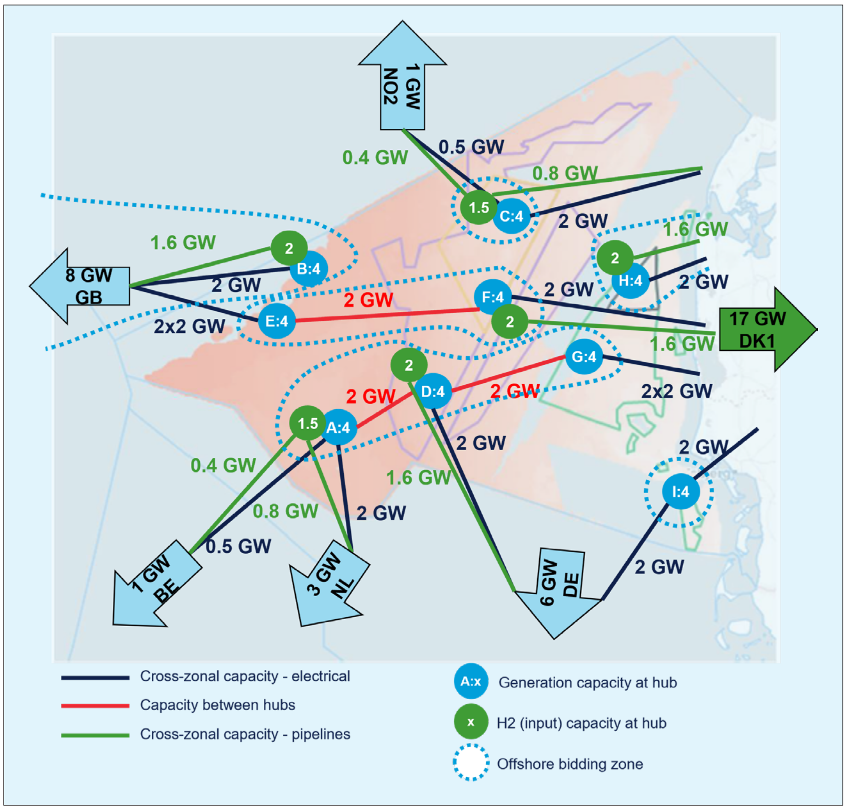
Table C-5 Allocation of offshore hydrogen production among hubs (Centralised)

CABLE		PIPELINE	
Cables A_BE	495	Pipe A_BE	495
Cables A_NL	254	Pipe A_NL	254
Cables A_D	51	Pipe B_GB	391
Cables B_GB	391	Pipe C_NO	300
Cables C_NO	300	Pipe C_DK	78
Cables C_DK	78	Pipe D_DE	262
Cables D_DE	262	Pipe F_DK	123
Cables D_G	60	Pipe H_DK	28
Cables E_GB	415		
Cables E_F	128		
Cables F_DK	123		
Cables G_DK	52		
Cables H_DK	28		
Cables I_DK	70		
Cables I_DE	163		

Table C-6 Assumed cable and pipeline length in Distributed concept (km)

Table C-7 contains the underlying data on the capacity of connection, where power connections are marked with blue colour.

CONCEPT 4 - Distributed - Hydrogen offshore - Combined Hydrogen and Electrical



	DK	DE	NL	BE	GB	NO	A	B	C	D	E	F	G	H	I	SUM TO SHORE
A			2 0.8	0.5 0.4						2						2.5 1.2
B					2 1.6											2 1.6
C	2 0.8					0.5 0.4										2.5 1.2
D		2 1.6					2						2			2 1.6
E					2x2							2				4
F	2 1.6										2					2 1.6
G	2x2									2						4
H	2 1.6															2 1.6
I	2	2														4
SUM	12 4	4 1.6	2 0.8	0.5 0.4	6 1.6	0.5 0.4										25 8.8

Table C-7 Line capacities in 'Distributed - Hydrogen offshore - Combined Hydrogen and Electrical' concept

The distribution of hydrogen production among hubs is given in Table C-8.

Hub	H2 on a hub (input GW)
A	1.5
B	2
C	1.5
D	2
F	2
H	2
TOTAL	**11**

Table C-8 Allocation of offshore hydrogen production among hubs (distributed)

APPENDIX D
CAPEX and OPEX data assumptions

APPENDIX D
CAPEX and OPEX data assumptions

Summary of applied component costs

		ONSHORE			OFFSHORE		
		CAPEX (mEUR)	OPEX	Area m²	CAPEX (mEUR)	OPEX	Area m²
Cables (bipoles)	0.5 GW 525 kV cable				1.64	2.50%	
	1 GW 525 cable				1.89	2.50%	
	1.5 GW 525 kV cable				2.14	2.50%	
	2 GW 525 kV cable				2.47	2.50%	
HVDC converter (bipole)	0.5 GW 525 kV converter	137.6	0.70%				
	1 GW 525 converter	179	0.70%		214.8	1.5%	35.000
	1.5 GW 525 kV converter	220.2	0.70%		264.3	1.5%	45.000
	2 GW 525 kV converter	261.7	0.70%		314.0	1.5%	60.000
HVAC transformer	210/30 kV, 700 MVA	7.5	0.15%				
	210/30 kV, 500 MVA	5.1	0.15%				
HVDC GIS	525 kV (per connected terminal)				5.6	0.15%	
HVAC GIS	132 kV (per converter)				1.9	0.12%	3.6 (L) x 1.0 (W) x 2.7 (H)
DCCB	525 kV DCCB				17	1.00%	12,5 (L) x 7.5 (W) x 14.5 (H)
Support structure	2 GW platform				390	1%	
	4 GW caisson				780	1%	
	8 GW island				1,560	1%	
	10 GW island				1,800	1%	
Electrolyser	0.5 GW electrolyser	500	1.5%				
	1 GW electrolyser	1,000	1.5%				
	1.5 GW electrolyser				1,575	2%	25,000
	2 GW electrolyser	2,000	1.5%		2,100	2%	33,333
	2.5 GW electrolyser	2,500			2,625	2%	41,667
	3 GW electrolyser	3,000			3,150	2%	50,000
	4 GW electrolyser				4,200	2%	66,667
	5 GW electrolyser	5,000	1.5%				
H2 pipes	0.4 GW pipe				1.5	0.5%	
	0.8 GW pipe				1.7	0.5%	
	1.6 GW pipe				2.5	0.5%	
	3.2 GW pipe				3	0.5%	

Transmission costs background

1. GENERAL BACKGROUND TO THE DNV COST ESTIMATES

The input data for the transmission equipment unit cost is taken from the DNV in-house transmission equipment database. The database is developed based on public data about the offshore wind and interconnector projects realised in the North Sea. This primarily concerns German, Dutch and British projects. The database is continuously updated with the most recent data from newly built projects, in this way ensuring its adequacy for the latest developments.

2. COMPONENT SPECIFIC CONSIDERATIONS

For HVDC cables, DNV will consider two separate cables (plus and minus pole) which will be laid in parallel to connect the HVDC converter station with symmetric monopole or rigid bipole topology. A third metallic return cable will be considered if the topology of "bipole with metallic return" is selected for the HVDC converters.

For HVDC converters we consider half-bridge voltage source converters (HB VSC), except for the topology Option 1C, where full-bridge configuration is applied (FB VSC). For HVDC converters with identical technology, the most important technical parameters are among others the DC voltage and power rating. We assume that converters with identical DC voltage level and power rating will have similar costs in terms of power electronics components. It is expected that control & protection will be more complex and converter transformers will be more demanding in bipole (both rigid bipole and bipole with dedicated metallic return) topology than their counterparts in the symmetric monopole topology. Such differences will be addressed in the cost estimation. All required DC switchgear and DC busbars are included as a part of the converter costs.

The type of platform design impacts the platform cost. There are three main types of platform design: jacket, jack-up and gravity-based solution (GBS). Jacket is expected to be in the lower range of the cost interval, while jack-up and GBS design are more expensive. The platform cost increases with the water depth; a taller substructure is needed for deeper water. More complex seabed increases the installation cost. Higher wind and/or wave load increases the need for a stronger and heavier substructure. The transportation and installation costs differ depending on the installation concept.

DCCBs are relatively new components with limited installations, the cost estimation of DCCB was done in a bottom-up approach based on our understanding of the most promising solutions (mechanical DCCB).

3. FACTORS CONTRIBUTING TO CAPEX

In what follows we show the cost breakdown for different elements contributing to the total cost of each equipment type with their corresponding percentage. The cost elements include the cost of equipment, installation and transportation, civil works, project management, right of ways, risk contingency and profit margin. The R&D cost is also included but differs between mature technology and new technology. In this project, we do not include any products still under development, so the R&D portion is low. The cost is implicitly included in the cost of equipment. The cost level shown in the report is inflation-adjusted to year 2021. The project management cost is included in cost breakdown for each category by component/subsystem, as such not as separate cost items to the high-level project cost. Figure D-1 shows an overview of CAPEX breakdown for primary components per category.

4. FACTORS CONTRIBUTING TO OPEX

OPEX cost for AC and DC systems include periodic maintenance of equipment which typically includes the following tasks:

- Scheduled maintenance of the foundation and structure
- Scheduled maintenance of the topside and electrical equipment
- Scheduled maintenance of the electrical equipment at the onshore substation
- Scheduled maintenance of cables

Costs included in OPEX are labour, spare parts, consumables, supply and accommodation vessels, crew transfer vessels or helicopter costs if applicable, travel expenses for staff and overnight accommodation, waste disposal and management.

Replacement costs are not included in the OPEX, since all major transmission equipment is designed at least for the lifetime equal to that of an offshore wind farm. The only subsystem which may need replacement is control and communication systems. Typically to be designed for 15-year lifetime. OPEX costs for the transmission equipment are defined as an annual percentage of CAPEX.

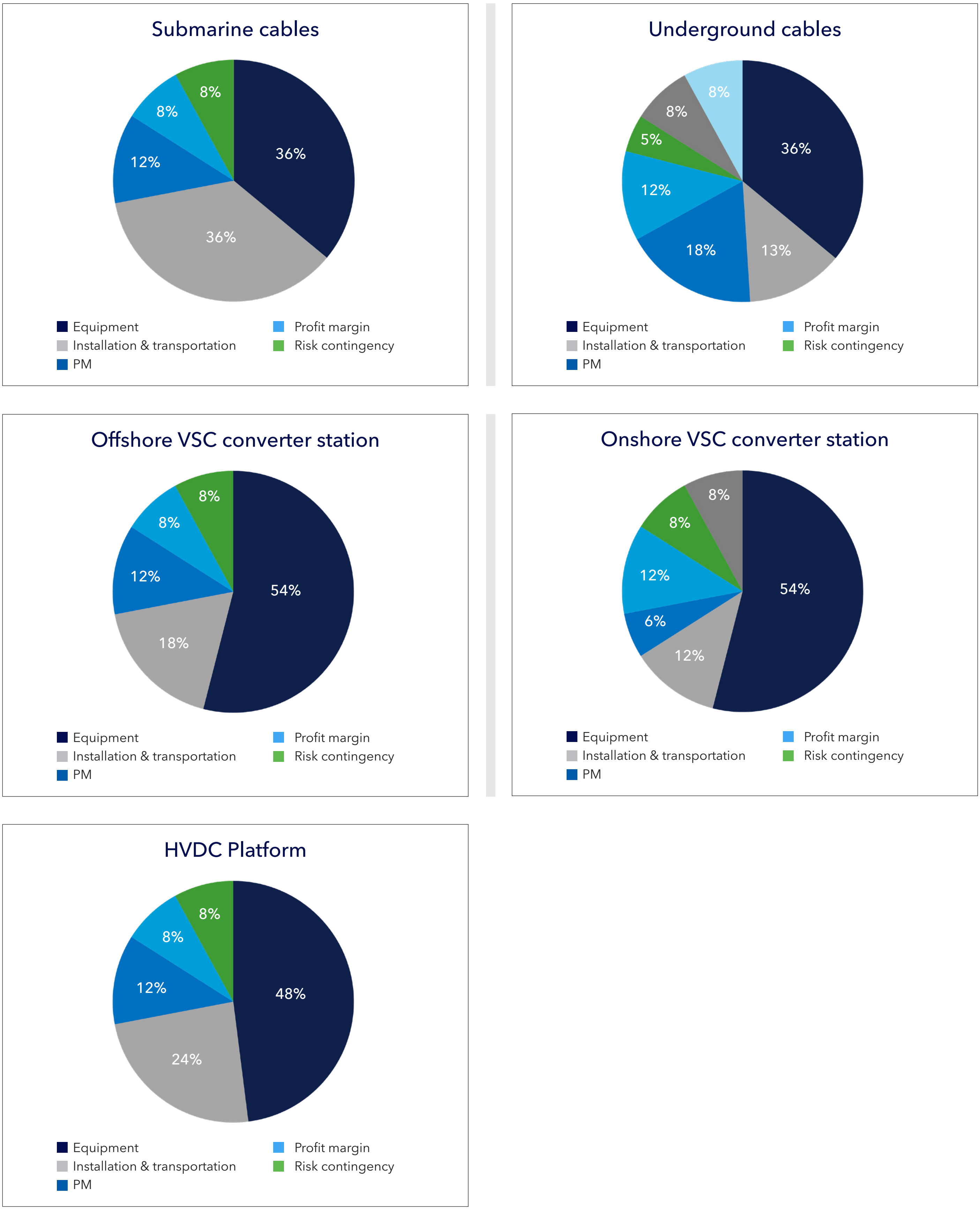


Figure D-1 CAPEX breakdown for primary components

Hydrogen production and transportation costs background

1. GENERAL BACKGROUND TO THE DNV COST ESTIMATES

DNV has performed multiple projects to assess the costs of onshore and offshore hydrogen production. These assessments are based on DNV's extensive cost database, continuous conversations with manufacturers and data from literature. In one of our most recent projects we have performed a detailed analysis of different offshore hydrogen production concepts in the North Sea. In this assessment we evaluated the main components, the technical challenges of integrating these into a functional system and the associated costs for each of the components and to overcome the technical challenges.

2. ELECTROLYSER COSTS ASSUMPTIONS

One of the main components for a hydrogen production plant is the electrolyser. The electrolyser consist of the stacks (the core of the system), the power supply and the balance of plant, containing gas treatment, desalination and water treatment, compression, the cooling system and the on-site distribution system. In addition, a building or containers add to the costs to house all equipment and to protect it from the environment.

An important aspect to the costs is the installation which adds roughly 70% to the direct costs if located onshore. Future developments and standardization could reduce this share although this is still to be further developed.

The costs in this study are derived from DNV's previous studies (2021) where we assessed the costs based on our concept engineering. These costs include the latest indications from electrolyser manufacturers, include economies of scale and include the costs of the other main components and costs for integrating those. The costs for desalination and water treatment are negligible.

3. DIFFERENCE BETWEEN ONSHORE AND OFFSHORE HYDROGEN COSTS

The offshore concept applied in this study is based on a hydrogen production plant located on an offshore platform. It is assumed that the topside will be manufactured onshore and will include all equipment. Therefore, the installation of equipment takes place onshore. The complete topside will then be transported to the offshore location where it is placed on the support structure. The main cost additions to an offshore hydrogen production plant are therefore the costs of the topside steelwork and grating, the costs of the support structure and the installation costs of both support structure and topside.

When considering hydrogen production on an island the building topology of the electrolysis plant could be similar to onshore. There will however be additional costs to transport and ship all equipment and personnel to the island. Alternatively, a more prefabricated (plug-and-play/containerized) approach can be taken to allow for easier transportation and installation. This is valid for the electrolyser, but also for all other equipment such as power supply, gas processing and compression.

DNV has also evaluated the suitability of electrolysers, intended for onshore, to be applied offshore. Based on conversations with manufacturers, the functional aspects of the system should be suitable for offshore application. Vibrations induced by waves should not prove an issue. Only rocking motion on floating structures could provide challenges to components containing fluids. This would require further assessment, but is irrelevant for the shallow part of the North Sea where bottom fixed structures are foreseen. The cost additions for different coating of components is expected to be negligible.

Another important aspect is operation and maintenance cost. It is still unclear how maintenance can be optimized/limited for offshore application but this could significantly increase costs. In case of unmanned operation, each maintenance action requires the mobilisation of a specialized vessel and crew. This is significantly more expensive compared to onshore and can add more than 50% to the maintenance costs.

It should be noted that DNV's assessment is based on current practice and future predictions for large scale hydrogen production plants, onshore or offshore. Large scale plants (>20 MW) currently do not exist and larger plants will be installed towards 2025. The current focus of the technology development is towards upscaling, performance improvement and cost reduction, mainly for onshore applications. Although systems might be suitable for offshore application, optimization should still be further evaluated.

4. H2 PIPELINES COSTS ASSUMPTIONS

DNV's assumptions for offshore pipeline costs are based on high level capacity calculations to obtain the correct pipeline diameter and are based on DNV's cost database including aspects such as steel price, diameters, wall thickness (max. operating pressure), coating and installation costs.

The transport capacity of a pipeline depends on the gas pressure, the gas velocity, the diameter and the length of the pipeline. These aspects are highly correlated and a change of one of the aspects results in a change of transport capacity. The assumptions used in this study are therefore high level as no specific case characteristics can be determined. The table below contains the main assumptions that were used to determine the pipeline diameter and costs.

A high-level indication for maintenance of offshore pipelines is 0.5% of the Capex annually.

Capacity	Max. operating pressure	Outlet pressures	Distance	Pipeline diameter	Installed costs
0.4 GW	80 bar	50 bar	100 km	10 inch	1.5 M€/km
0.8 GW	80 bar	50 bar	100 km	12 inch	1.7 M€/km
1.6 GW	80 bar	50 bar	100 km	18 inch	2.5 M€/km
3.2 GW	80 bar	50 bar	100 km	22 inch	3 M€/km

APPENDIX E
Bill of materials for Capex and Opex

APPENDIX E
Bill of materials for Capex and Opex

	HUB A			HUB B			HUB C			HUB D		
	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore
HVDC converter	2	4	offshore	2	4	offshore	2	5	offshore	2	5	offshore
DCCB		10	offshore		8	offshore		12	offshore		10	offshore
HVDC GIS		5			4			6			5	
Island/platform	2	4		2	4		10			10		
HVDC converter GB	2	3	onshore	2	1	onshore						
HVDC converter BE	1	1	onshore									
HVDC converter NO				1	1	onshore						
				2	2	onshore	2	5	onshore	2	1	onshore
HVDC converter DK				1	1	onshore	1	1	onshore			
										2	3	onshore
HVDC converter DE										1.5	2	onshore
HVDC converter NL												
Cables A_GB	2	3										
Cables A_BE	1	1										
Cables A_C	2	1										
Cables B_GB				2	1							
Cables B_NO				1	1							
				2	2							
Cables B_DK				1	1							
							2	5				
Cables C_DK							1	1				
Cables D_DK										2	1	
Cables D_DE										2	3	
Cables D_NL										1.5	2	
Electrolyser GB	2	1	onshore									
Electrolyser NO				0.5	1	onshore						
Electrolyser DK							5	1	onshore			
Electrolyser DE										2	1	onshore
Electrolyser NL										1	1	onshore
Electrolyser BE	0.5	1	onshore									
HVAC transformer GB	0.7	3	onshore									
HVAC transformer NO				0.5	1	onshore						
HVAC transformer DK							0.7	7	onshore			
HVAC transformer DE										0.7	3	onshore
HVAC transformer NL										0.5	2	onshore
HVAC transformer BE				0.5	1	onshore						

Table E-1 Bill of materials: Centralised - Hydrogen Onshore

	HUB A			HUB B			HUB C			HUB D		
	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore
HVDC converter	2	2	offshore	2	1	offshore	2	3	offshore	2	3	offshore
HVDC converter	1.5	1	offshore	1.5	3	offshore				1	1	offshore
DCCB		8	offshore		8	offshore		8	offshore		8	offshore
HVDC GIS		4	offshore		4	offshore		4	offshore		4	offshore
HVAC GIS		4	offshore		4	offshore		4	offshore		4	offshore
Island/platform	2	4		2	4		10			10		
HVDC converter GB	2	1	onshore	2	2	onshore						
HVDC converter BE	0.5	1	onshore									
HVDC converter NO				0.5	1	onshore						
				2	2	onshore	2	3	onshore	2	1	onshore
HVDC converter DK							1	1	onshore			
HVDC converter DE										2	2	onshore
HVDC converter NL										2	1	onshore
Cables A_GB	2	2										
Cables A_BE	0.5	1										
Cables A_C	2	1										
Cables B_GB				2	1							
Cables B_NO				0.5	1							
				2	2							
Cables B_DK												
							2	3				
Cables C_DK												
Cables D_DK										2	1	
Cables D_DE										2	2	
Cables D_NL										2	1	
Electrolyser	2.5	1	offshore	1.5	1	offshore	4	1	offshore	3	1	offshore
Pipe A_GB	1.6	380										
Pipe A_BE	0.4	481										
Pipe B_NO		332		0.4								
Pipe B_DK		235		0.8								
Pipe C_DK		76					3.2					
Pipe D_DE		277								1.6		
Pipe D_NL		298								0.8		

Table E-2 Bill of materials: Centralised - Hydrogen Offshore - Combined Electricity and Hydrogen

	HUB A			HUB B			HUB C			HUB D		
	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore	Capacity (GW)	Area/ quantity	Onshore/ offshore
HVDC converter	2	2	offshore	2	1	offshore	2	3	offshore	2	3	offshore
HVDC converter	1.5	1	offshore	1.5	3	offshore				1	1	offshore
DCCB		8	offshore		8	offshore		8	offshore		8	offshore
HVDC GIS		4	offshore		4	offshore		4	offshore		4	offshore
HVAC GIS			offshore			offshore						
Island/platform		4		2	4		10			10		
HVDC converter GB	2	1	onshore	2	2	onshore						
HVDC converter BE	0.5	1	onshore									
HVDC converter NO				0.5	1	onshore						
				2	2	onshore	2	3	onshore	2	1	onshore
HVDC converter DK							1	1	onshore			
HVDC converter DE										2	2	onshore
HVDC converter NL										2	1	onshore
Cables A_GB	2	2										
Cables A_BE	0.5	1										
Cables A_C	2	1										
Cables B_GB				2	1							
Cables B_NO				0.5	1							
				2	2							
Cables B_DK												
							2	3				
Cables C_DK												
Cables D_DK										2	1	
Cables D_DE										2	2	
Cables D_NL										2	1	
Electrolyser	2.5	1	offshore	1.5	1	offshore	4	1	offshore	3	1	offshore
Pipe A_GB	1.6	0										
Pipe A_BE	0.4	0										
Pipe B_NO		0		0.4								
Pipe B_DK		0		0.8								
Pipe C_DK		0					3.2					
Pipe D_DE		0								1.6		
Pipe D_NL		0								0.8		

Table E-3 Bill of materials: Centralised - Hydrogen Offshore - Dedicated OWF's for hydrogen production

	HUB A			HUB B			HUB C			HUB D			HUB E			HUB F			HUB G			HUB H			HUB I		
	Capacity (GW)	Area/quantity	Onshore/offshore	Capacity (GW)	Area/quantity	Onshore/offshore	Capacity (GW)	Area/quantity	Onshore/offshore	Capacity (GW)	Area/quantity	Onshore/offshore	Capacity (GW)	Area/quantity	Onshore/offshore	Capacity (GW)	Area/quantity	Onshore/offshore	Capacity (GW)	Area/quantity	Onshore/offshore	Capacity (GW)	Area/quantity	Onshore/offshore	Capacity (GW)	Area/quantity	Onshore/offshore
HVDC converter	1	1	offshore	2	1	offshore	1	1	offshore	2	1	offshore	2	2	offshore	2	1	offshore	2	2	offshore	2	1	offshore	2	2	offshore
HVDC converter	1.5	1	offshore				1.5	1	offshore																		
DCCB		4	offshore					2	offshore		4	offshore		4	offshore		2	offshore		4	offshore					2	offshore
HVDC GIS		3	offshore					2	offshore		3	offshore		2	offshore		2	offshore		3	offshore					2	offshore
HVAC GIS		3	offshore		2	offshore		2	offshore		2	offshore					2	offshore					2	offshore			
Island/platform	2	2		2	2		2	2		2	2		2	2		2	2		2	2		2	2		2	2	
HVDC converter GB				2	1	onshore							2	2	onshore												
HVDC converter BE	0.5	1	onshore																								
HVDC converter NO							0.5	1	onshore																		
HVDC converter DK							2	1	onshore							2	1	onshore	2	2	onshore	2	1	onshore	2	1	onshore
HVDC converter DE										2	1	onshore													2	1	onshore
HVDC converter NL	2	1	onshore																								
Cables A_BE	0.5	1																									
Cables A_NL	2	1																									
Cables A_D	2	1																									
Cables B_GB				2	1																						
Cables C_NO							0.5																				
Cables C_DK							2																				
Cables D_DE										2	1																
Cables D_G										2	1																
Cables E_GB													2	2													
Cables E_F													2	1													
Cables E_DK																2	1										
Cables G_DK																			2	2							
Cables H_DK																						2	1				
Cables I_DK																									2	1	
Cables I_DE																									2	1	
Electrolyser	1.5	1	offshore	2	1	offshore	1.5	1	offshore	2	1	offshore				2	1	offshore				2	1	offshore			
Pipe A_BE	0.4																										
Pipe B_NL	0.8																										
Pipe B_GB				1.6																							
Pipe C_NO							0.4																				
Pipe C_DK							0.8																				
Pipe D_DE										1.6																	
Pipe F_DK																1.6											
Pipe H_DK																						1.6					

Table E-4 Bill of materials: Distributed - Hydrogen Offshore - Combined Electricity and Hydrogen

APPENDIX F
Detailed breakdown of Capex and Opex results

APPENDIX F
Detailed breakdown of Capex and Opex results

The hub placements and cable lengths have not been optimised. This limits comparability between concepts, especially comparing Concept 4 to other concepts.

CAPEX - detailed breakdown

The detailed breakdown into component types, given in Table F-1, indicates that in terms of the contribution to the total CAPEX electrolysers, HVDC cables and support structures account for roughly 70% of the total, regardless of the concept.

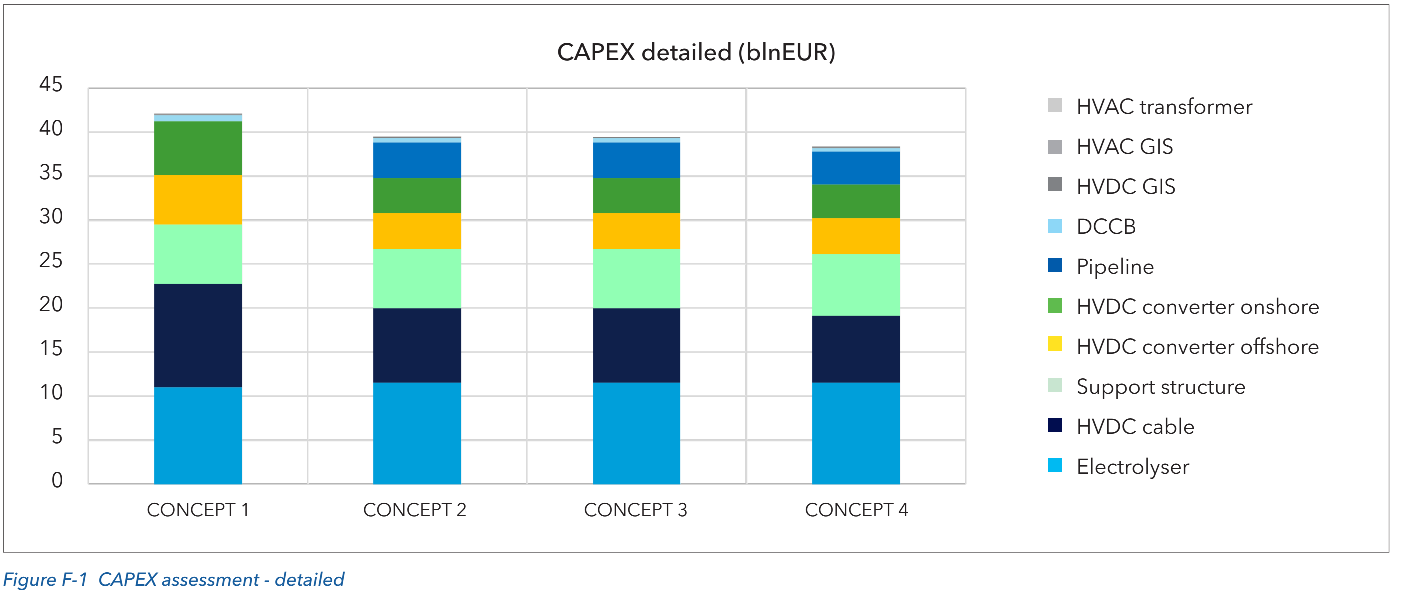


Figure F-1 CAPEX assessment - detailed

CAPEX (bnEUR)	Concept 1 Centralized - H2 onshore	Concept 2 Centralized - H2 offshore - combined electricity and H2	Concept 3 Centralized - H2 offshore - dedicated gas connection	Concept 4 Distributed - H2 offshore - combined electricity and H2
Electrolyser	11.0	11.6	11.6	11.6
HVDC Cable	11.8	8.4	8.4	7.6
Support structure	6.7	6.7	6.7	7.0
HVDC Converter offshore	5.7	4.1	4.1	4.1
HVDC Converter onshore	6.1	4.0	4.0	3.8
Pipeline	0.0	4.0	4.0	3.8
DCCB	0.7	0.5	0.5	0.4
HVDC GIS	0.1	0.1	0.1	0.1
HVAC GIS	0.00	0.03	0.00	0.02
HVAC Transformer	0.03	0.00	0.00	0.00
TOTAL	**42.1**	**39.5**	**39.4**	**38.3**

Table F-1 CAPEX assessment data - detailed

OPEX - detailed breakdown

Table F-2 presents the underlying data split into component types.

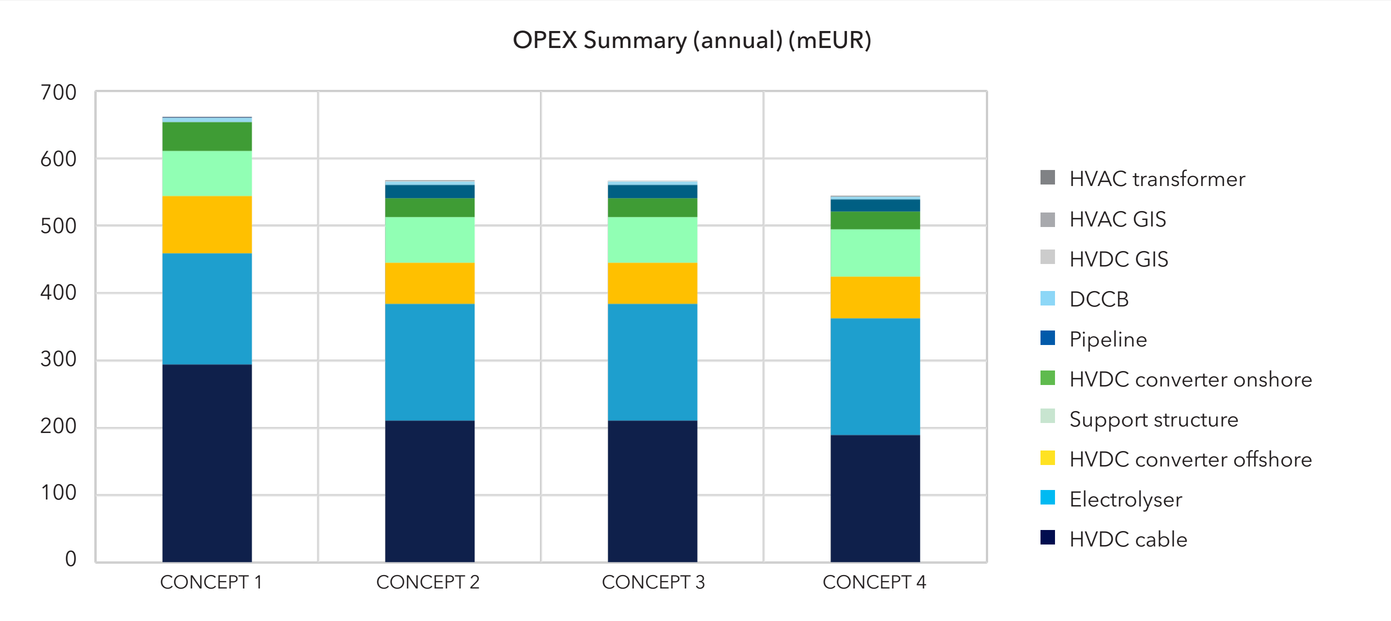


Figure F-2 OPEX assessment - detailed

CAPEX (bnEUR)	Concept 1 Centralized - H2 onshore	Concept 2 Centralized - H2 offshore - combined electricity and H2	Concept 3 Centralized - H2 offshore - dedicated gas connection	Concept 4 Distributed - H2 offshore - combined electricity and H2
HVDC Cable	294.2	211.0	211.0	189.6
Electrolyser	165.0	173.3	173.3	173.3
HVDC Converter offshore	84.8	61.5	61.5	61.5
Support structure	67.2	67.2	67.2	70.2
HVDC Converter onshore	42.7	27.9	27.9	26.4
Pipeline	0.0	20.0	20.0	18.8
DCCB	6.8	5.4	5.4	3.7
HVDC GIS	0.2	0.1	0.1	0.1
HVAC GIS	0.0	0.0	0.0	0.0
HVAC Transformer	0.0	0.0	0.0	0.0
TOTAL	**660.9**	**566.4**	**566.4**	**543.6**

Table F-2 OPEX assessment data

	CONCEPT 1	CONCEPT 2	CONCEPT 3	CONCEPT 4
Cables 2 GW	€ 8,368	€ 7,106	€ 7,106	€ 6,279
Cables 1.5 GW	€ 1,275			
Cables 1 GW	€ 2,124			
Cables 0.5 GW		€ 1,333	€ 1,333	€ 1,304
Pipeline 0.4 GW		€ 1,220	€ 1,220	€ 1,193
Pipeline 0.8 GW		€ 800	€ 800	€ 498
Pipeline 1.6 GW		€ 986	€ 986	€ 1,206
Pipeline 3.2 GW		€ 114	€ 114	

Table F-3 Comparison of total cable and pipeline cost per capacity level (mEUR)

APPENDIX G
Technology readiness level scale

APPENDIX G
Technology readiness level scale

Technology Readiness Level (TRL) is an indicator of the maturity levels of a particular technology. In EU, the universal usage of TRL scale in EU policy was proposed and consequently implemented in the subsequent EU Horizon 2020 framework program (H2020). The TRL scale H2020 is generic: no sound definition of individual levels has been fully explained and exemplified for the electricity T&D sector yet. In order to adapt the original TRL scale for specific organisation or program, the TRL scale needs to be adapted and customised accordingly.

0	Idea
1	Basic principles observed
2	Technology concept formulated
3	Experimental proof of concept
4	Technology validated in lab
5	Technology validated in industrial environment
6	Technology demonstrated in industrial environment
7	System prototype demonstration in operational environment
8	System complete and qualified
9	Actual system proven & competitive manufacturing

Figure G-1 TRL scale

The adapted H2020 TRL for T&D Sector is described in the following:

TRL 1 – Basic principles observed
Initial scientific research has been conducted. Basic principles are observed. Focus is on analytical studies on fundamental understanding of the principle.

TRL 2 – Technology concept formulated
Technology concept is formulated based on the analytical studies. Practical applications of the technology are identified or predicted.

TRL 3 – Experimental proof of concept
Technology concept/analytical prediction of the technology is validated by initial laboratory-scale measurements. Modelling/simulation validation in software are considered as the experimental proof of the technology concept.

TRL 4 – Technology validated in lab
Individual technology components and their functionalities are tested to work as theory in lab-scale.

TRL 5 – Technology validated in relevant environment
(industrially relevant environment in the case of key enabling technologies)
Individual technology components and their functionalities are tested to work as theory in industrial environment, where the industrial environment is a representative engineering environment. Independent labs, real-time simulator, and National HVDC centre etc. are regarded as industrial environment.

TRL 6 – Technology demonstrated in relevant environment
(industrially relevant environment in the case of key enabling technologies)
Individual technology components are tested with each other as a semi-integrated system. The semi-integrated system with its functionalities is tested and confirmed to work as expected in an industrial environment using the real system input.

TRL 7 – System prototype demonstration in operational environment
The prototype of full-scale integrated system with its functionalities are tested and confirmed to work as expected in an operational environment (on-site environment e.g. outside manufacturers laboratory) using the real system input.

TRL 8 – System complete and qualified
Integrated system with its functionalities is proven to work as expected against industrial norms/standards.
The manufacturing process is considered as preliminary.

TRL 9 – Actual system proven in operational environment
(competitive manufacturing in the case of key enabling technologies)
Actual operating system as a developed technology with its full functionalities is proven to work under full range of operating conditions. The developed technology is ready for commercial production and delivery.
The manufacturing process is optimised.

ABOUT DNV

We are the independent expert in risk management and assurance. Driven by our purpose, to safeguard life, property and the environment, we empower our customers and their stakeholders with facts and reliable insights so that critical decisions can be made with confidence. As a trusted voice for many of the world's most successful organizations, we use our knowledge to advance safety and performance, set industry benchmarks, and inspire and invent solutions to tackle global transformations.

In the energy industry

We provide assurance to the entire energy value chain through our advisory, monitoring, verification, and certification services. As the world's leading resource of independent energy experts and technical advisors, we help industries and governments to navigate the many complex, interrelated transitions taking place globally and regionally, in the energy industry. We are committed to realizing the goals of the Paris Agreement, and support our customers to transition faster to a deeply decarbonized energy system.

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