WHEN TRUST MATTERS

COST AND PERFORMANCE DATA FOR OFFSHORE HYDROGEN PRODUCTION

Danish Energy Agency

REPORT

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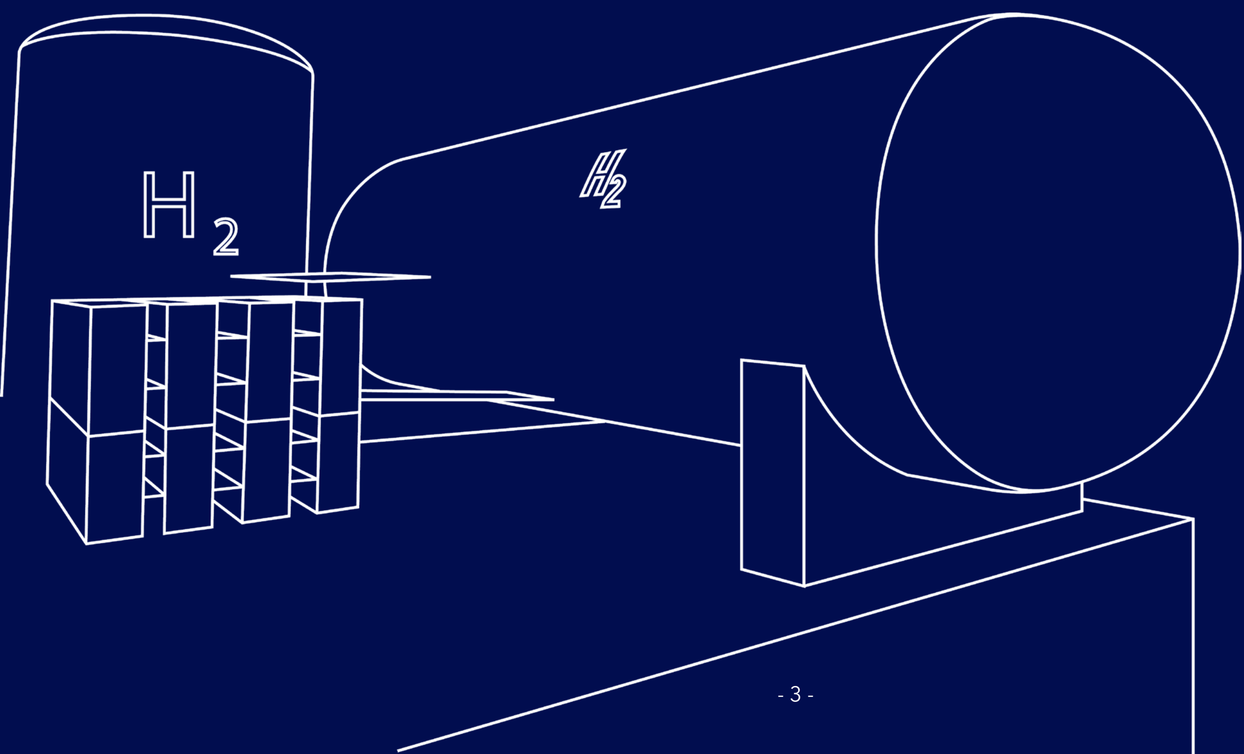
1. INTRODUCTION



1. INTRODUCTION

The Danish Agency is looking at how to accelerate the development of offshore wind and integrate hydrogen production technologies with offshore wind in different ways. The integration of offshore wind and hydrogen production at a large scale will require new technological solutions.

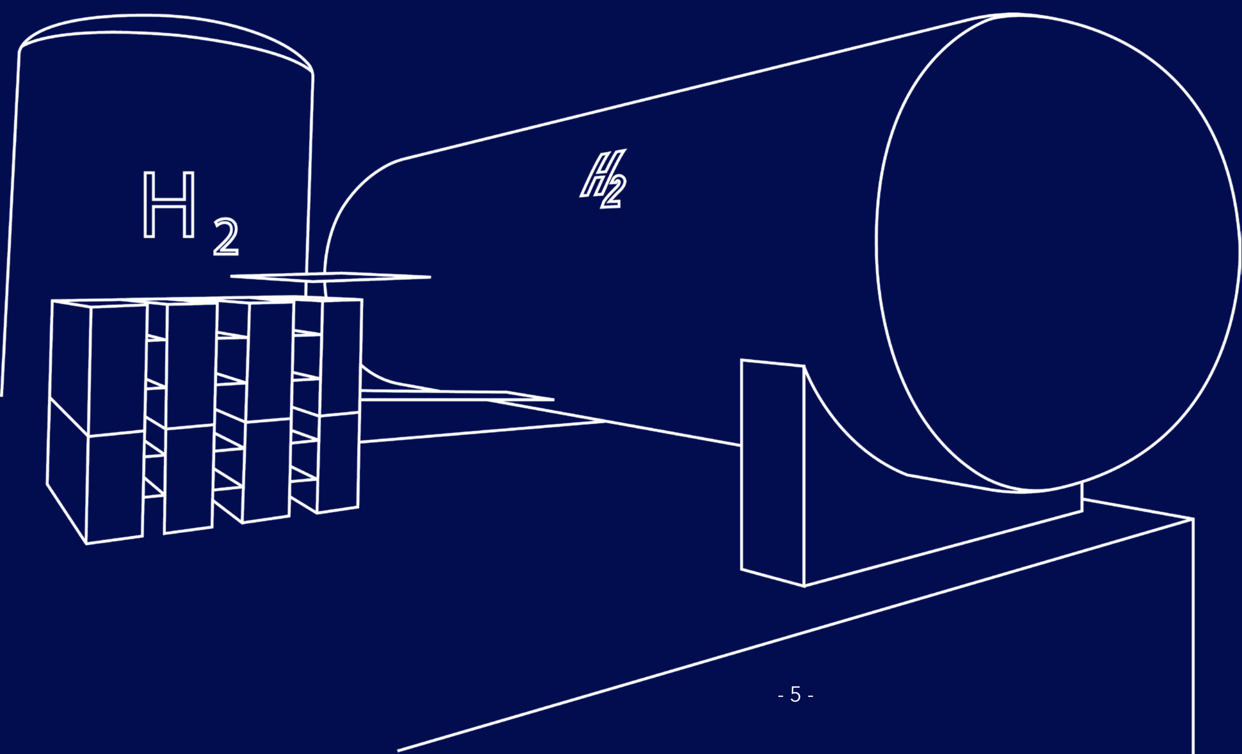
In order to do proper cost-benefit analysis of hydrogen production the Danish Energy Agency has asked for an assessment of CAPEX and OPEX of different technologies to calculate levelized cost of hydrogen at an onshore landing point. Hydrogen can either be produced offshore or the electricity can be transported onshore and converted at an offshore landing point.

DNV has assisted the Danish Energy Agency in obtaining relevant CAPEX, OPEX and performance data in various offshore technologies related to hydrogen production and to complement their own technology catalogue.

The selected technologies relevant for offshore hydrogen production which are considered in this report are listed below.

- Transformers
- Electrolyser
- Water treatment/cooling
- Offshore platform substructure
- Offshore turbine substructure
- Offshore installation and maintenance
- Array pipelines

2. BASIS FOR WORK



2. BASIS FOR WORK

The work in this report is intended for analysing value chains on the shallow part of the North Sea. The provided data is valid within the following boundaries (Table 2-1). Additional limitations or information is provided in the dedicated sections of this report.

TOPIC	COMMENTS
Capacity	GW Scale offshore wind farms
Water depth	20 - 60 metres with 35 metres as most common
Distance from shore	50 - 300 km
Timescale	2035 -2050
The cost figures provided only consider costs for equipment and installation. Engineering, indirect costs, contingency and owner's costs are not included.	

Table 2-1: Main boundaries for the scope of this work

The next section provides and overview of different concepts for producing hydrogen from offshore wind and describes the system boundaries which form the basis for the cost functions in this report.

2.1 Offshore hydrogen production concepts

Hydrogen production through electrolysis uses electricity to split water into hydrogen and oxygen. This electricity can be generated by renewable sources such as wind energy and with a direct connection to the source. The figure 2-1 on page 7 provides three possible configurations for connecting an electrolyser plant to an offshore wind farm.

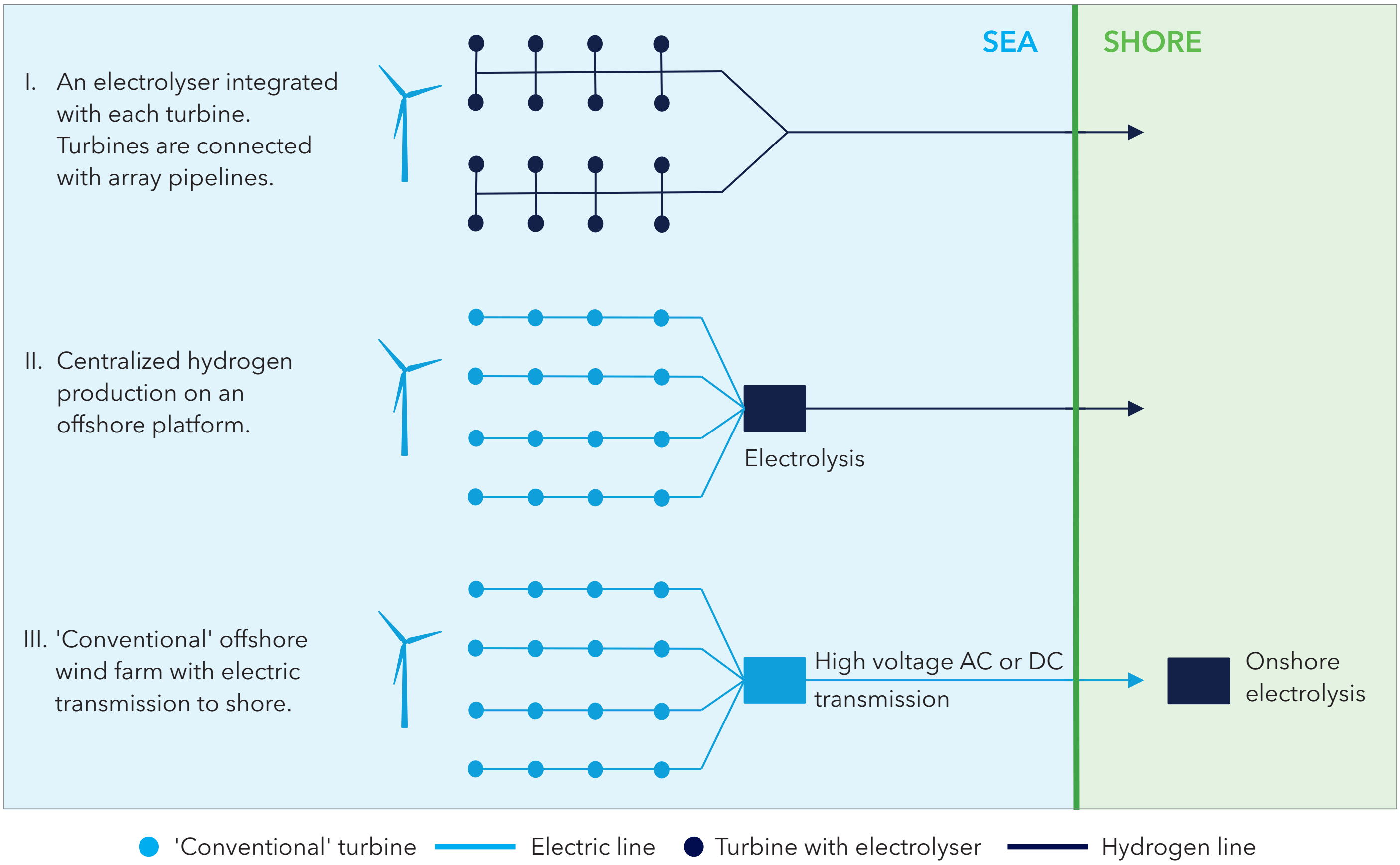


Figure 2-1: Offshore hydrogen production concepts

I. The first configuration integrates the hydrogen production at the turbine. A smaller electrolyser unit is directly connected to the turbine to generate hydrogen and will omit the requirement for array cables. Instead array pipelines are used.
II. The second configuration still resembles a conventional offshore wind farm but will not connect to the grid. Instead, the electrolyser plant is part of the infrastructure to transport energy to shore. The electrolyser plant is located on a centralized platform (comparable to a substation) and is receiving electricity from the array cables.
III. The third configuration is more conventional where a wind farm is built and instead of connecting to a grid, it is directly connected to the electrolyser plant which is located onshore.
IV. The three configurations can be dedicated where all electricity is converted to hydrogen, but alternatively a hybrid system can be chosen. A hybrid system still has both a connection to the grid as well as a connection to the electrolyser. Both connections, electric and hydrogen, can be at full capacity or a smaller part of the capacity. E.g. for a 15 MW hybrid turbine, 10 MW can be converted to hydrogen with a 10 MW electrolyser and the remaining 5 MW can be connected electrically. The connecting infrastructure, array pipes and cables and further export pipes and cables should be designed to the required capacity as well. Such a system allows the operator to choose between different markets (hydrogen or electricity).

This report mainly focusses on concept I and II and are further elaborated below. Here DNV provides their high-level view on a potential design, but it should be noted that further research and development is still needed. System schematics are provided on the next pages and used as the basis for providing system boundaries to the systems further described in this report.

The provided cost data is complementing DEA's technology catalogue. Cost data of components that are not included in this report can be found in the catalogue.

2.1.1 INTEGRATED CONCEPT - HYDROGEN PRODUCTION AT THE OFFSHORE TURBINE

The integrated concept assumes hydrogen production at the turbine where an electrolyser is located at the base of the turbine. Additional support structure is required to extend the working platform of the turbine for the hydrogen production equipment to be placed in containers. This equipment includes the electrolyser, water treatment and cooling and receives medium voltage (10-40 kVAC) from the turbine. Seawater is used for both cooling and desalination and treated to supply clean water to the electrolyser. To further transport the produced hydrogen, a connection will be made to array pipelines which collect hydrogen from each turbine and further transport it to a manifold or central compressor.

At this stage DNV took a simplistic approach that combines hydrogen production equipment with a “conventional” turbine (AC output). Further optimization may integrate the electrolyser at the DC side of the turbine generator which can reduce losses and omit costs for DC/AC conversion. However, there is still much research needed to further evaluate and overcome technical challenges which could add other equipment such as a back-up system. The concept of directly connecting electrolysis to renewable energy without grid support is still new and might provide challenges when starting up the turbine after it has been idle or for providing power to ancillary systems. This will likely require additional components such as a back-up system which have not yet been included in this scope.

Other optimizations can also be found in the design of the turbine. The design of a turbine, the generator size and the rotor diameters assume certain economic considerations and optimizations. The optimum for a “conventional electric turbine” could differ from the optimum design for a hydrogen turbine. By changing the rotor diameter or generator, the utilization or maximum yield can be influenced. With the additional costs for hydrogen production equipment a different optimum design can be found. Such an approach is also described in [1]. Optimizations such as described above could reduce the hydrogen production costs from offshore wind but are still to be further developed and evaluated by industry. The system boundaries of the integrated turbine are provided in the schematics below (Figure 2-2).

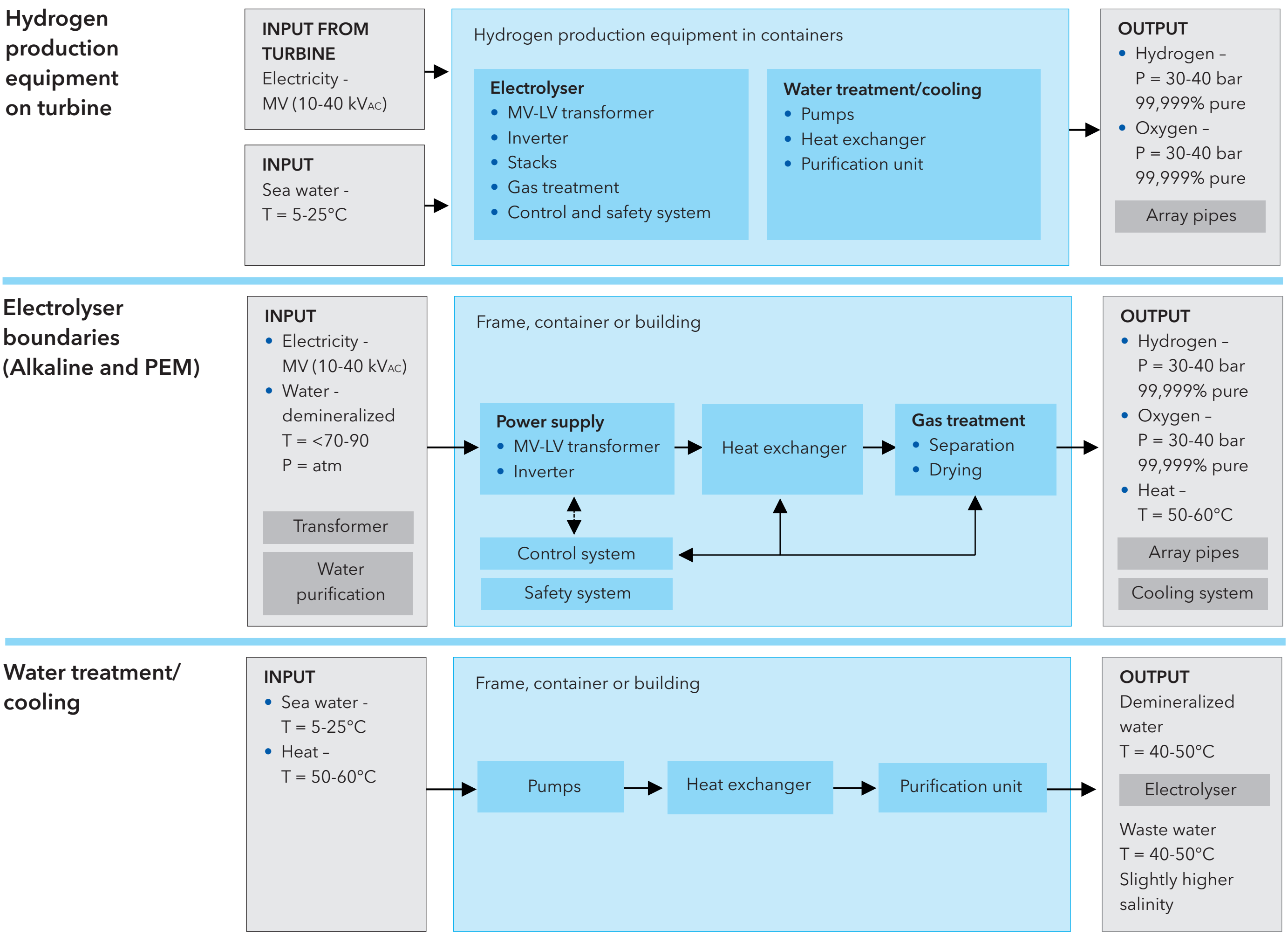


Figure 2-2: Schematics for integrated concept, hydrogen production directly at the offshore turbine

2.1.2 CENTRALIZED PLATFORM CONCEPT - HYDROGEN PRODUCTION ON AN OFFSHORE PLATFORM

The platform concept assumes hydrogen production on an offshore platform where multiple turbines are connected through array cables. The voltage received at the platform is 66-132 kVAC where it is transformed to medium voltage (10-40 kVAC) through a transformer system.

Other equipment on the platform includes the electrolyser, the water treatment and the cooling. This concept also uses sea water for cooling and desalination and water treatment to provide clean water. All equipment is placed on multiple decks and the system boundaries are further clarified by the schematics below.

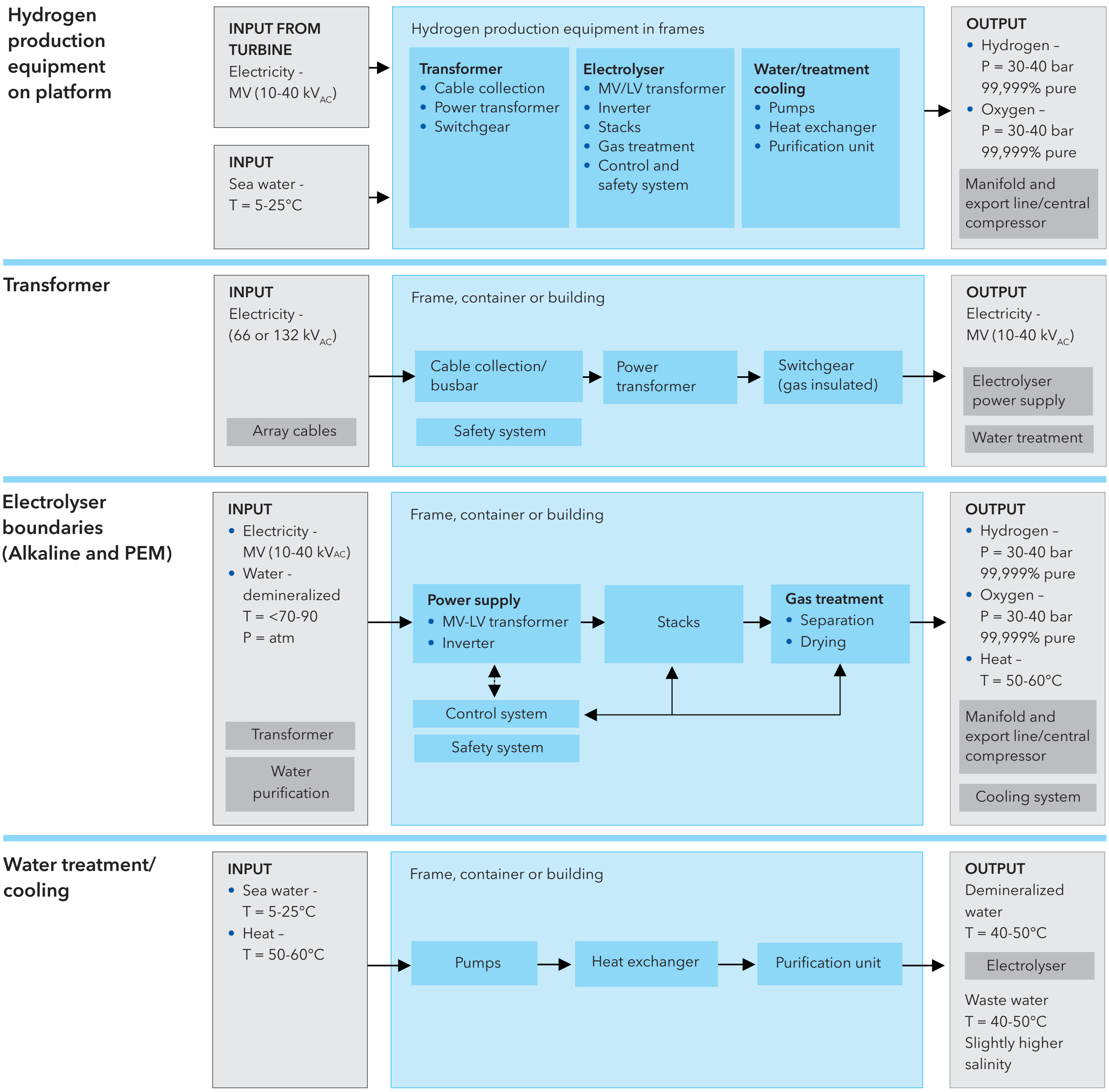
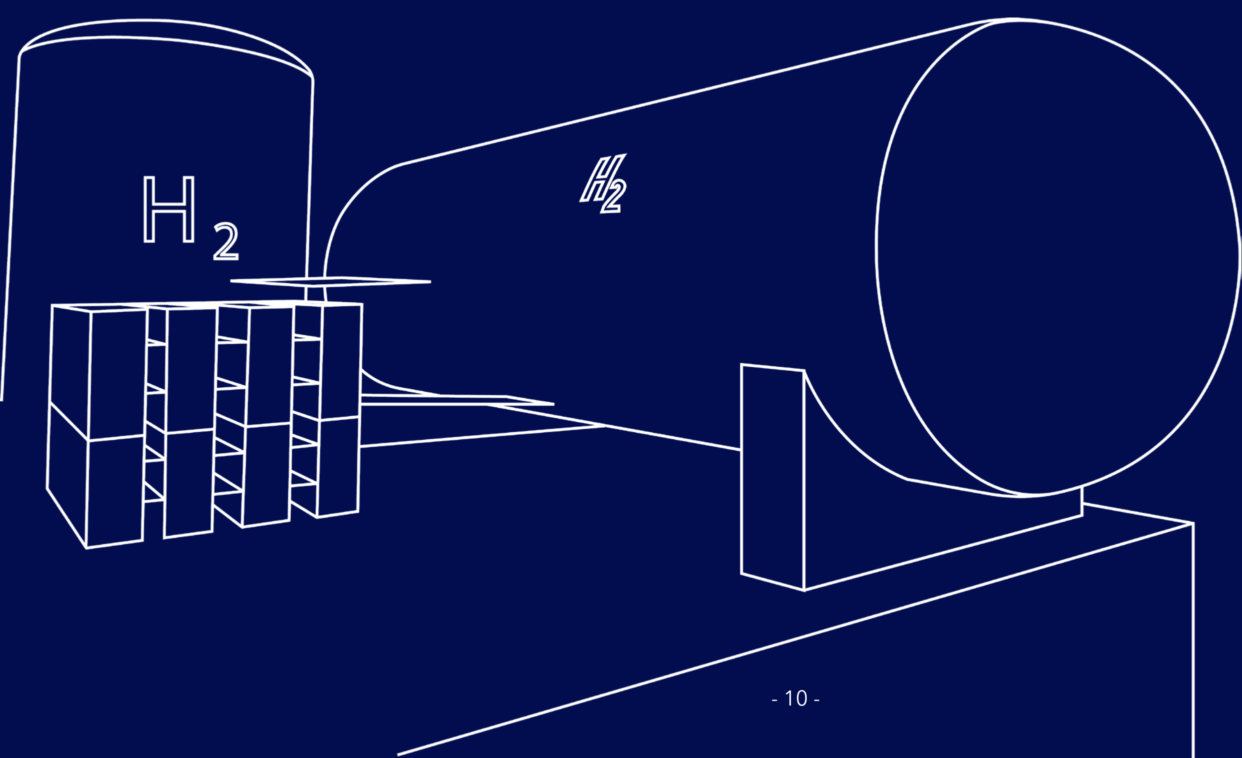


Figure 2-3: Schematics for platform concept, hydrogen production on an offshore platform

3. COST AND PERFORMANCE DATA



3. COST AND PERFORMANCE DATA

3.1 Transformers for hydrogen production

Hydrogen product Turbine output and array voltage is currently being standardized at 66 kV_{AC} and possibly increasing to 132 kV_{AC} in the future. Hydrogen production through electrolysis however is typically done at relatively low voltages and direct current (<1.5 kV_{DC}). The voltage should therefore be reduced while minimizing losses throughout the electrolysis plant. An intermediate voltage (typically 10-40 kV_{DC}) is therefore often used to transport electricity throughout the plant where the last voltage reduction step and conversion is done through the inverters which are considered part of the electrolysis plant. This section provides a cost and performance estimate for the power equipment needed on a hydrogen production platform.

The configuration of such power equipment depends on capacity to feed into a platform and the required level of protection. To provide a high-level cost and performance estimate a concept configuration for a 646 MW_{el} offshore hydrogen plant is used. The configuration includes transformers and gas insulated switchgear (GIS). The configurations are visualized below.

The cost difference between both configurations is considered minimal and a simplified cost of 33,100 €/MW is derived for the configurations described above. This is excluding installation on the platform topside which should add roughly 20-30%. Additional installation costs should be added for installing the complete topside, which is further elaborated in chapter 3.5 and 3.6.

The costs are considered to scale linearly with capacity and no big cost reductions expected from technology development. Other cost and performance components are provided in the table below (Table 3-1).

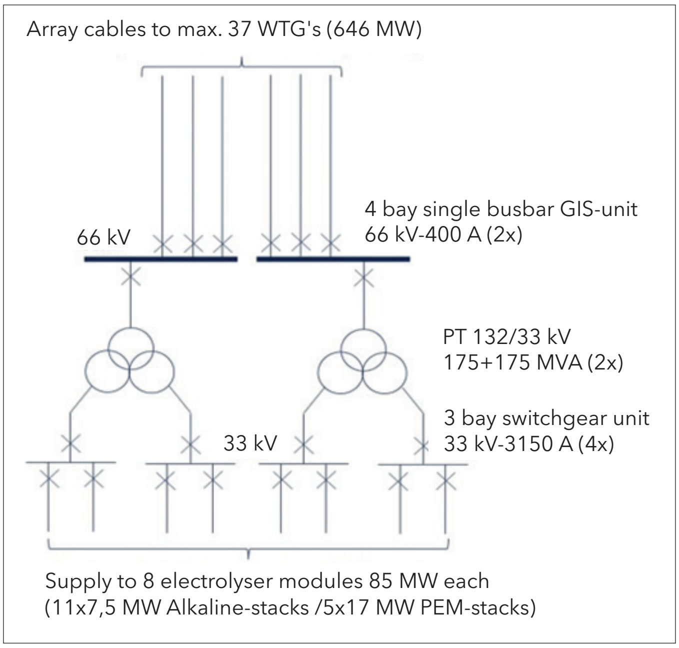


Figure 3-1: Supply station 66/33 kV - 646 MW (at platform)

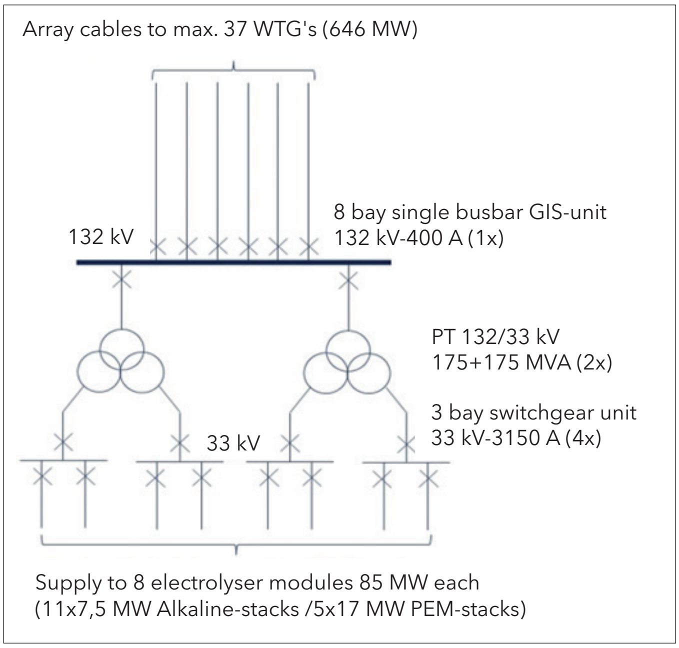


Figure 3-2: Supply station 132/33 kV - 646 MW (at platform)

	OPEX	EFFICIENCY	WEIGHT	AREA
66/33 kV configuration	1% of CAPEX annually	98%	865 kg/MW	0.54 m^2/MW
132/33 kV configuration	1% of CAPEX annually	98%	1,065 kg/MW	0.72 m^2/MW

Table 3-1: Cost and performance of transformer configurations for offshore hydrogen production

3.2 Electrolyser

Electrolysers have been operating for multiple decades already, but the energy transition has provided a boost for further development and upscaling. The main developments are related to upscaling of both systems and supply chain, improvement of performance, cost reduction and application/ integration with renewable energy. These developments are mainly focussing for onshore application, but offshore application is increasingly being explored.

Offshore application requires a direct coupling to renewable energy and therefore a rapid response time, should have a minimized footprint and weight and should have minimized maintenance requirements. Currently only pressurized alkaline and PEM can meet these requirements and even with those technologies, further development is needed. Anion Exchange Membrane (AEM) could be another potential technology but is currently immature and its future is still uncertain. In this section we therefore only focus on pressurized alkaline and PEM.

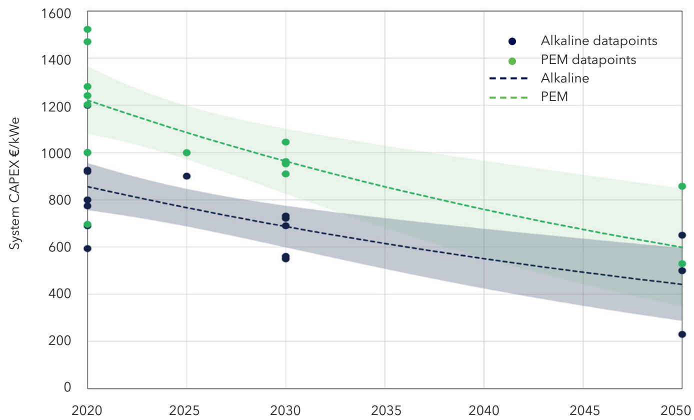


Figure 3-3: System CAPEX development of Alkaline and PEM for 1 MW reference

Based on large set of public data and vendor data, the data points in the figure below (Figure 3-3) have been corrected for size and represent a 1 MW system. For larger systems, scaling formulas should be applied which are further elaborated in section 3.2.1. A fit and uncertainty are included in the figure and are based on the datapoints. These considered system costs which include both stack (typically 30%-50% of the costs) and balance of plant (typically 50%-70% of the costs. For some sources there is uncertainty on the limits for the balance of plant and could include items such as compressors or civil works/containers. In addition, there is much uncertainty around the cost due to the low maturity of the market and the uncertainty is increasing towards the future. It is expected that Alkaline and PEM will move closer to each other and could reach an equal cost level. None the less, both technologies will see a large cost reduction where costs could be half of the current levels towards 2050.

For onshore applications the installation can add 30-70% to the system costs, depending on size. For smaller scale plants in containerized units the installation costs tend to be lower as these solutions are easier installed (plug-and-play). For larger plants more installation work is performed on-site, increasing the costs for installation. The installation costs therefore depend on system design and especially for the larger scale systems the installation costs are uncertain as large scale plants still have to be built. The provided range applies to onshore costs and are based on a limited number of indications from electrolyser suppliers and industry experts. For installing an electrolyser offshore, additional costs can be expected which are further elaborated in section 3.6.

The emphasis for technological development is currently on onshore electrolysis, but there are also developments for offshore application. At this stage it is still unclear what exact technological developments are required as well as what additional design considerations should be made. During conversations with electrolyser suppliers, some do not expect a significant cost increase on equipment costs, but this is still to be verified in a more detailed design phase. The main increase is likely with the installation and maintenance cost which is further elaborated in section 3.6. The increased cost for offshore maintenance might ultimately drive further development which could reduce maintenance costs but increase CAPEX. This balance is however still to be further evaluated.

As the electrolyser technologies mature, performance will also improve. The main performance aspects are power consumption and lifetime of the stack. The figures below (Figure 3-4) provide a fit to data points from literature and vendors for both the power consumption and stack lifetime. The power consumption is provided as the electric power consumption in KWh per Nm³ of hydrogen produced. The figure again comprises the whole system.

Power consumption can decrease as system load or current density decreases. This results in lower resistive losses. With fluctuating renewable energy connected to an electrolyser, lower power consumption can occur when wind turbines or solar panels are not operating at normal capacity. This effect is however not included in this study. On the other hand higher energy consumption can be expected as the system ages and components in the stack degrade. Fluctuating operation can have an accelerating effect on degradation, however, this effect should still be further studied by the industry.

The stack lifetime is provided in operating hours which represent operation at full load. There is still much unknown about degradation with partial load or intermittent operation. Degradation leads to a decrease in efficiency and as a rule of thumb, a stack reaches its lifetime after the efficiency has decreased by 10%. The figure below (Figure 3-5) is based on this 10% decrease in efficiency. This is of course an economic consideration as less or more efficiency loss can be accepted for a viable business case. A simple approach is to calculate the number of full load hours (e.g. 2 hours at 50% load count as 1 full load hour) and use the values in the figure to determine the time of stack replacement.

Other cost and performance components are provided in the table below (Table 3-2). Note that the weight and area are based on high level indications by suppliers and are based on current figures. For large scale hydrogen production and offshore hydrogen production further development can still be expected.

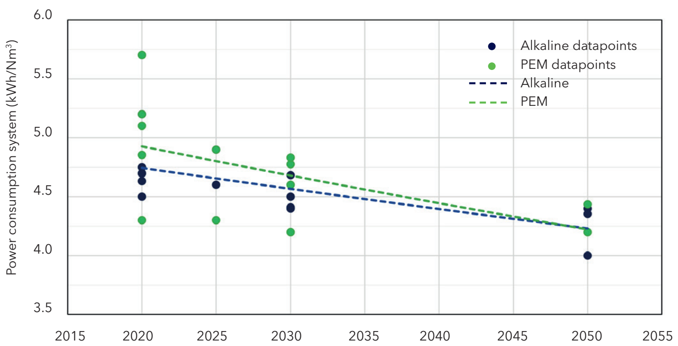


Figure 3-4: Development of system power consumption of Alkaline and PEM for 1 MW reference

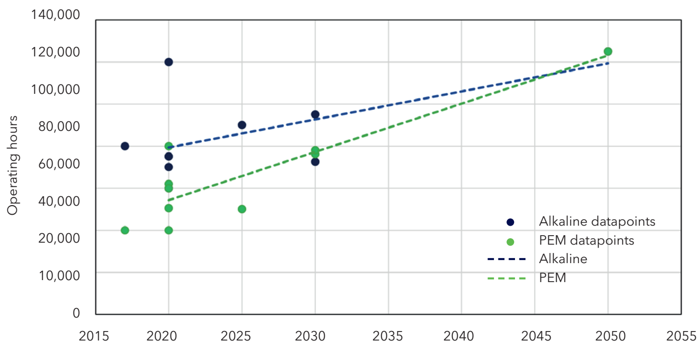


Figure 3-5: Development of stack lifetime of Alkaline and PEM for 1 MW reference

	OPEX	WEIGHT*	AREA*
Alkaline	1-3% of CAPEX annually	8,500 kg/MW	30 m²/MW
PEM	1-3% of CAPEX annually	7,000 kg/MW	

* Weight and area are based on currrent figures for MW sized systems and the effect of scaling is not evaluated. A simplistic approach assumes linear scaling.

Table 3-2: Cost and dimensions for electrolysers

3.2.1 SCALABILITY OF ELECTROLYSERS

Significant cost reduction can be achieved for electrolysers through economies of scale. The costs of certain components do not scale linearly with an increase in capacity and provide a cost advantage. This applies especially to vessels/tanks and pipes which make up a large part of the balance of plant[1] (BoP) of an electrolyser plant. A rule of thumb to estimate the economies of scale is called the 0.6 rule. With each increase in size, the cost will increase with an exponent of 0.6. In an electrolyser plant however, a large part of the costs are for the stacks which do not have such scaling advantages. After reaching the stack capacity (a few MW depending on the manufacturer) scaling up simply means applying more stacks. Therefore, the stacks do not have much economies of scale after a few MW, while the BoP does have economies of scale.

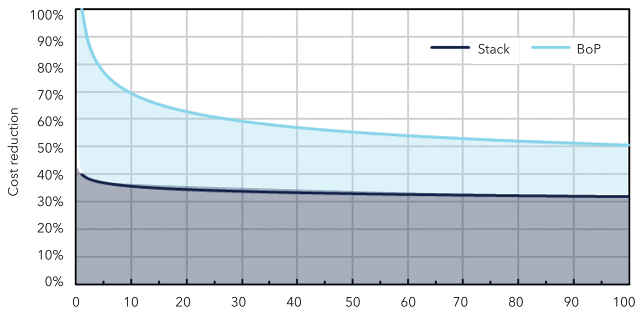


Figure 3-6: Economies of scale for an electrolyser

A simple approach to evaluate the economies of scale of the electrolyser plant (stacks and BoP) is therefore to apply different scaling exponents. DNV used data received from manufacturers and public data to find a good fit for scaling stacks and the BoP. The stacks should scale almost linear and a scaling factor of 0.95 provided a good fit. For the BoP a good fit was found with a scaling factor of 0.75. The scaling factors can be used to calculate the cost advantage when scaling up according to the formulas below and can be applied to the system costs provided in the section above. These economies of scale only apply to the system costs of the electrolyser and should not include installation cost.

$$\textit{Scaling advantage stacks (\%)} = (\textit{Electrolyser capacity (MW)}^{0.95}) / \textit{Electrolyser capacity (MW)} * 100\% \qquad 1$$

$$\textit{Scaling advantage BoP (\%)} = (\textit{Electrolyser capacity (MW)}^{0.75}) / \textit{Electrolyser capacity (MW)} * 100\% \qquad 2$$

The effect of economies of scale is also provided in Figure 3-6.

It can be seen that after larger capacities there is less cost advantage and scaling become linear again. In real this would also be the case as components cannot scale up endlessly and there is a certain limit to the economies of scale. It should be further evaluated where this limit actually is. In addition, this is a simplistic approach to scaling up and as the electrolyser industry is still growing and maturing, other cost effects might disrupt the scaling effect shown here. Cost of electrolysers still varies much between suppliers. Furthermore, the economies of scale also depend on how the plant is designed. If the plant is designed with many repetitive units of a smaller scale, there is less scaling advantage.

A conceptual design of a large scale electrolyser plant (GW-scale) was done by ISPT and provides a reference for a possible design concept [2]. The design assumes a modular approach where modules are repeated to increase total capacity. Economies of scale apply to a single module and will decrease after modules are repeated.

[1] The balance of plant in this study includes both the electrical systems and gas systems (medium voltage transformers and rectifiers, a control system, cables and pipes, pumps, heat exchangers, liquid/gas separators, dryers, and gas purification and treatment).

3.3 Water treatment/cooling

Sea water is available in abundance for producing hydrogen offshore but requires purification. The water quality has a direct influence on the electrolyser performance and degradation and is therefore an essential process step. In addition, sea water can also be used for cooling, which is commonly done in offshore O&G applications. With the electrolysis process a large amount of heat is available and should be cooled. This heat can also be used to desalinate sea water through thermal desalination. This allows for integrating the water treatment system with the cooling system.

With thermal desalination, heat is used to evaporate water leaving impurities behind in a reject stream. When the vapour condenses it contains less impurities. The main source of energy is heat and only a small amount of electricity is used to power the pumps. Thermal desalination can operate at relatively low temperatures of <60°C which perfectly fits with the available heat from the electrolyser. Heat from the electrolyser process stream is exchanged through plate heat exchangers and cools the electrolyser while using the heat to desalinate the sea water.

Additional treatment should be added to further clean the water and get it to the required purity. For electrolysers this is typically indicated as a water conductivity requirement and is in the range of <5 µS/cm for alkaline and <1 µS/cm for PEM. The volume of clean water required to produce 1 Nm³ of hydrogen is approximately 1 litre which roughly equates to 0.3 m³/h of clean water per MW of electrolyser. To produce 1 m³ of clean water the process uses approximately 6 kWh of electric energy to power pumps etc. and 750 kWh of thermal energy which is roughly 60% of the available heat from the electrolysis process (assuming 75% HHV electrolyser efficiency).

DNV received cost indications and technical specification of a water treatment unit from a supplier which are provided in Table 3-3.

Reverse osmosis is an alternative water treatment technology and uses filters and pumps to clean water. Further research should be performed to evaluate which technology is better suited.

When applying reverse osmosis, the water treatment system and cooling system are decoupled and should be costed separately. While cooling with sea water will likely still be the preferred solution, other cooling technologies like air coolers have been more commonly applied with onshore electrolysis. It is to be evaluated if such an option would be suitable for offshore application as this could be prone the wet and saline environment. In addition, it should also be evaluated if air coolers are favorable with large scale electrolysis as large amounts of heat need to be cooled to the air.

3.4 Cost for platform sub-structure

Offshore platforms have been deployed in the oil and gas industry for many years and are well developed. Although the application for offshore hydrogen production is new and likely requires adaptations to "conventional" design (e.g. different safety measures, standardization of design, etc.) a rough cost estimate can be made based on historical data. To estimate platform costs for offshore hydrogen production, DNV uses its experience and data from an extensive list of other projects, mainly based in the North Sea.

The weight of an offshore hydrogen production plant depends on the selected electrolyser technology and its capacity but in DNV's experience a jacket structure will be the preferred option for bottom fixed solutions (monopiles will not have enough carrying capacity).

System CAPEX	13.000 €/MW of electrolyser capacity (cost developments are still unknown)	
Installation	10% of system CAPEX	
OPEX	2% of system CAPEX	
Lifetime	25 years	
Energy use	Heat: 750 kWh/m³ of water	Electricity: 6 kWh/m³ of water
Area	1 m³ per MW of electrolyser capacity	
Weight	500 kg per MW of electrolyser capacity	

Table 3-3: Cost data and technical specifications of water treatment by thermal desalination

The costs for a platform are divided into costs for the topside structure, costs for the substructure/jacket and the costs for foundation. A visualization of the three elements is provided in Figure 3-7.

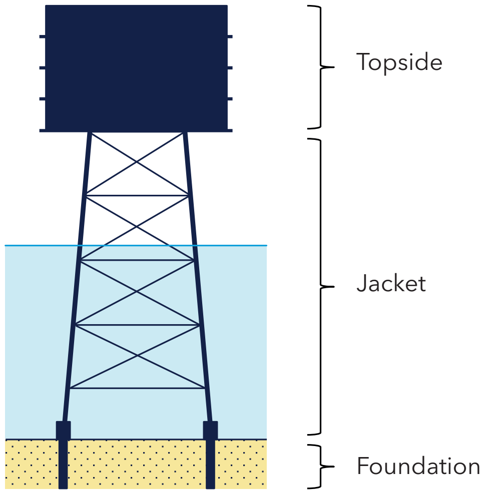


Figure 3-7: Main elements of an offshore jacket platform

Topside structure

The topside structure will house all process equipment (transformers, electrolysers, gas treatment etc.) that is needed for hydrogen production. In oil and gas, this topside is often completely built onshore, including the installation of most process equipment. The complete topside is then lifted by large installation vessels and placed on the substructure that is already installed at the offshore production location. DNV assumes a similar approach for offshore production platforms for hydrogen. The costs for the topside structure depend on the mass, surface area and required facilities. DNV found the mass to be dominant in determining the costs (for hydrogen production applications).

The mass of the process equipment will determine the amount of steel required and as a rule of thumb, the mass of the topside structure is equal to the mass of the process equipment (complete topside mass is equipment mass + topside structure mass itself). The costs for the topside structure are then determined by multiplying the estimated topside structure mass in tonne by a cost factor for steel work of 6,000-9,000 €/tonne (Table 3-4).

$$\textit{Topside structure cost}\ (EUR) = \textit{topside structure mass}\ (tonne) * 7{,}500 \qquad (3)$$

Steel cost factors

To determine the costs for the offshore structures a cost factor is used. This factor includes costs for steel, assembly, paint/coating and other costs related the offshore structures. This cost factor differs per structure element (topside/platform, jacket and piles) due to complexity of the assembly. The table below provides an overview of the applied steel cost factors in section 3.4 and 3.5.

STRUCTURE ELEMENT	STEEL COST FACTOR
Topside structure/working platform	6,000 - 9,000 €/tonne
Jacket	2,800 - 4,000 €/tonne
Foundation/piles	1,000 - 2,000 €/tonne

Dependency on fluctuations in the steel market and labour are unknown.

Table 3-4: Steel cost factors for offshore structures

Substructure/jacket

The substructure/jacket rises from the seabed to the water surface and will support the topside. The costs are depending on the type of seabed, the water depth, the weight it should support and the wave conditions. To simplify DNV assumes typical conditions for North Sea with a sandy seabed and a significant wave height of 10-15 m.

To estimate costs, first the jacket mass is determined. A relationship between water depth and topside mass is derived from a large set of installed or designed northern European (and a small number in the Gulf of Mexico) platforms for both O&G and renewables.

The jacket mass is determined per unit water depth by the derived formula below and should be multiplied by the water depth. The estimated height above sea level (generally 20-30 m) to stay out of wave range is already included in this formula.

To calculate the jacket cost, the jacket mass (in tonne) is multiplied by a cost factor for jacket steel work of 2,800-4,000 €/tonne (Table 3-4). This cost factor is lower than for the topside as steel work for the jacket is less complicated.

Note that the topside structural mass is calculated with formula 3 and the complete topside mass includes the topside structural mass and equipment mass.

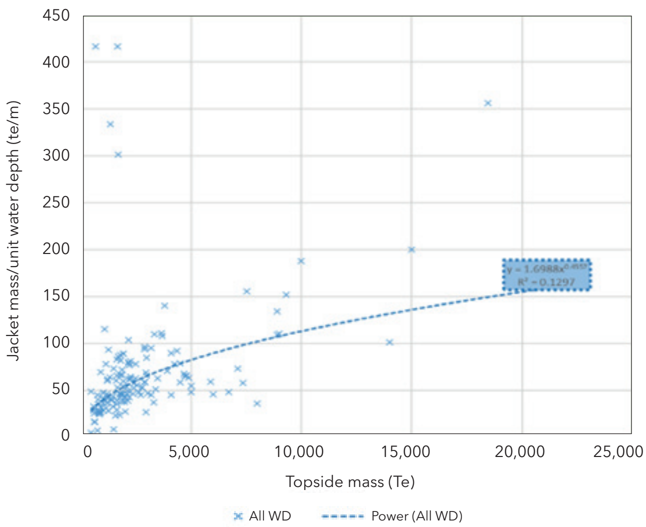


Figure 3-8: Jacket mass per unit water depth vs topside mass

Piles/foundation

Piles and foundation of an offshore structure are highly dependent on the soil conditions, currents, water depth and the structure that it should support (jacket and topside). A high-level estimate for the pile/foundation costs can be made on the required mass. DNV derived a general formula with the jacket mass and topside mass as variables. Again, a cost factor is used for pile steel work of 1,000-2,000 €/tonne (Table 3-4).

The jacket mass is calculated by following formula 4 and the topside structural mass is calculated with formula 3 (complete topside mass is double the structural mass).

$$\textit{Jacket structure mass (tonne)} = \textit{water depth (m)} * 1.7 * \textit{topside mass (tonne)}^{0.4557} \quad (4)$$

$$\textit{Jacket cost (EUR)} = \textit{jacket structure mass (tonne)} * 3{,}400 \quad (5)$$

$$\textit{Pile/foundation cost (EUR)} = (0.0235 * (\textit{jacket structure mass (tonne)} + \textit{topside mass (tonne)}) + 534) * 1{,}500 \quad (6)$$

3.5 Cost for turbine sub-structure

Jackets are commonly used substructures for offshore wind farms in the North Sea. They are considered most suitable for water depths below 80 m or large turbine sizes of 10MW or larger. Jackets generally sit on piled foundations which are driven into the seabed and provide vertical stability. The main alternative to jacket substructures is the monopile support structure which is more widely used but generally better suited to shallower waters due to fabrication limitations that constrain the maximum monopile diameter, and due to dynamic interactions between the monopile and cyclic loading from waves and the WTG's rotor which reduce the monopile's maximum lifetime. This section therefore focusses on jacked structures for both "conventional" turbines and hydrogen generating turbines.

Hydrogen generating turbines are still conceptual and the design is unknown. This section therefore assumes DNV's view on how a hydrogen generating turbine could be designed. This design assumes the jacket working platform to be extended to allow for placing electrolysis equipment. The equipment includes the power transformers, converters, stacks, gas treatment, water treatment, cooling and other equipment which is placed on the platform in (40 ft.) shipping containers. The figure on the right provides a visualization.

The costs for the sub-structure are again divided into three cost elements, costs for the extended working platform, costs for the jacket and the costs for foundation. While electrolysis equipment will increase the vertical load of the jacket, it is actually other loads that determine the design. Adding electrolysis equipment to a turbine will therefore only affect the costs for the working platform and has no effect on the costs for the jacket and foundation. The cost increase can be considered limited compared to the costs for the complete substructure.

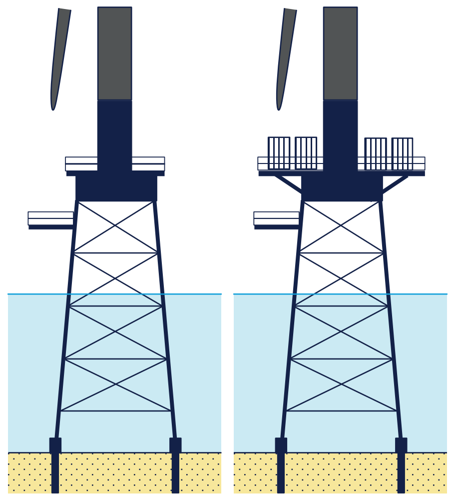


Figure 3-9: Main elements of an offshore turbine sub-structure
Left: a 'conventional' jacket structure
Right: an extended structure for hydrogen production

To determine the sub-structure mass and costs DNV uses mass relationships based on reports of jacket masses in the public domain, results from DNV design studies, and DNV's understanding of how jacket mass scales with water depth and turbine rating. Mass is converted to cost by using a cost rate for jacket fabrication. The formulas below provide cost figures for the complete turbine substructure.

Working platform

The substructure to support electrolysis equipment is based on a calculation for the area of platform required to support the equipment. It's assumed that the electrolysis equipment is stored on the jacket's main working platform which is considered a secondary part of the structure (i.e. this part of the structure is not subject to global or primary loading from the WTG rotor or wave action). The formulas below are used to determine the mass and cost of the working platform. A cost factor for steel work of 6,000-9,000 €/tonne is used for the working platform (Table 3-4).

Working platform mass (tonne)

$$= \left[\left(\sqrt{\frac{\textit{turbine power (MW)}}{0.00031}} \cdot 0.0368 + 3 \right) + \textit{area for hydrogen equipment } (m^2) \right] \cdot 0.25 \qquad 7$$

$$\textit{Working platform cost (EUR)} = \textit{working platform masse (tonne)} * 7{,}500 \qquad 8$$

Jacket

The cost of the jacket is derived using quadratic equations which predict mass of the jacket as a function of water depth and turbine rating (using a generic turbine and general North Sea conditions). The formulas below are used to determine the mass and cost of the jacket. A cost factor for steel work of 2,800-4,000 €/tonne is used for the jacket (Table 3-4).

Piles/foundation

The cost of piles are linear equations as functions of water depth and turbine rating. The formulas below are used to determine the mass and cost of the piles. A cost factor for steel work of 1,000-2,000 €/tonne is used for the piles (Table 3-4).

$$\begin{aligned} \textit{Jacket mass (tonne)} &= (0.0013 + \textit{turbine power}\,(MW) + 0.055) * \textit{water depth}\,(m)^2 \\ &+ (0.1 * \textit{turbine power}\,(MW) + 6.3) * \textit{water depth}\,(m) + (100 + \textit{turbine power}\,(MW) - 237.5) \end{aligned} \tag{9}$$

$$\textit{Jacket cost}\,(EUR) = \textit{jacket mass}\,(tonne) * 3{,}400 \tag{10}$$

$$\begin{aligned} \textit{Pile mass}\,(tonne) = [&(0.2826 \cdot \textit{turbine power}\,(MW) - 0.9476) \cdot \textit{water depth}\,(m) \\ &+ (6.9983 \cdot \textit{turbine power}\,(MW) + 513.26)] \end{aligned} \tag{11}$$

$$\textit{Pile cost}\,(EUR) = \textit{pile mass}\,(tonne) * 1{,}500 \tag{12}$$

3.6 Offshore installation and maintenance

3.6.1 INSTALLATION

The installation method for offshore hydrogen production plants depends on the selected concept (on an Island, on a platform or integrated with the turbine) and how the plant is designed. These aspects are currently still being worked out by industry and the costs for installation in this section are purely based on DNV's view. Further research and more detailed design are needed for more accurate costs.

The installation costs are based on vessel day rates which DNV received from an offshore operator and estimated duration for installations. Although these rates will likely vary significantly, due to future developments, market demand and contractual agreements, a projection towards 2025 was provided and assumed to represent future rates as well. The used day-rates are provided in Table 3-5.

VESSEL TYPES AND DAY RATES (€/DAY)	LOW	HIGH
Light construction vessels 20-250t	61,657	85,367
Construction 250-400t	97,510	121,310
Construction 400-1000t	137, 276	162,776
Large heavy lift 7000-14000t (day rate including operational cost)	1,000,000	1,000,000
North Sea Barge with two tugs (day rate including operation cost)	29,000	31,000

Table 3-5: Day rates for installation vessels received from an offshore operator (2025 projections)

Equal to the vessel day rate, the duration of the operations is the second driver for the cost of offshore installation. Several factors influence the time spent to complete the transport and installation operations. The factors below are included in the study:

- Vessel transit speed (kts) as given in the vessel specifications for similar vessel types in the relevant vessel category.
- T/R distance to mobilisation port (nm), taken as 160nm for the platform and the integrated concepts and 100nm for the island concept.
- Transit time (h) based on the T/R distance divided by the transit speed.
- Port turnaround time (h), estimated based on the amount of work to be performed during port call/mobilisation.
- Total number of port calls (x-number) estimated based on vessel deck space, object size and number of objects to be transported or installed. A maximum deck utilisation of 60% for construction vessels and 80% for barges has been assumed.
- Installation time (h) estimated based on the amount of work to be performed during installation on site.
- Weather factor for estimated additional waiting on weather. Generally, a factor of 1.25 to 1.35 is used for larger installation operations assumed to be performed during favourable installation season and 1.45 for all year operations. For the unloading of modules using shore-based crawler type crane, a factor of 1.1 is used.
- Onsite installation and fastening of structures based on a factor of 2.5% of object weight multiplied by 1700 €/t.

Both day-rates and duration are included in a DNV model which is used to estimate installation costs. The outcomes of the model are provided below as well as a more detailed description of the installation method. A distinction is made between hydrogen production on a centralized platform and a decentralized concept with hydrogen production integrated with a turbine.

Platform concept

For the installation of the hydrogen production plant on a platform a similar approach is taken to conventional O&G platforms. A complete topside is built and equipped onshore (step 1) and lifted and installed by large offshore installation vessels (step 2).

1

The topside contains all process equipment (transformers, electrolyser, gas treatment, desalination, etc.) which is being installed onshore as a first step. A high-level assumption is taken that the installation costs to install process equipment on the topside is similar to installing process equipment in buildings as would happen in an onshore plant. These were described in section 3.2 and found to add 30-70% to the costs of the equipment itself and are not included in the cost estimates in this section and should be added in addition to the costs provided in Table 3-6.

2

A second step is the installation of the complete topside on the offshore location which includes lifting, transport and installation. This includes lifting the topside on a barge for transportation and on the offshore destination to lift the topside on the jacket structure. Section 3.4 elaborated on the costs for the topside structure, the jacket structure and foundation itself, and the costs for installation are included in the table below. The table includes the installation cost for 1 hydrogen production platform (topside, jacket and piles) and assumes a case where the offshore location is located 100 km from shore. The total installed hydrogen production capacity per platform is 700-800 MWe (pressurized alkaline or PEM) to stay below the maximum lifting capacity of 14,000 t. The low and high costs refer to the uncertainty of the vessel rates provided in Table 3-5.
The costs in Table 3-6 provide a reference and have a certain level of uncertainty. The vessel rates are received from one operator and apply to his fleet. Other operators will likely have a different range of lifting capacities and different rates. It should also be noted that the costs are based on the lifting capacity but in reality, a different approach can be taken which might require more lifting vessels (when it is inconvenient to lift the complete load with one vessel). Such uncertainties should be solved in a more detailed design phase.

Additionally, there are assumptions made on distance and topside weight.

- Lighter topsides with a smaller hydrogen production capacity will likely still have similar installation costs per platform as the same range of installation vessels are used. For other operators this might however be different.
- The distance has an impact on the required duration and therefore installation costs. 100 km was assumed as a a base. With a 50 km distance, the installation costs can reduce by 5% and a distance of 200 or 300 km will increase the installation costs by 10% or 20% (respectively).

COMPONENT	VESSEL TYPE	TOTAL DURATION (DAYS)	ONSITE INSTALLATION COST (EUR)	TOTAL INSTALLATION COST (EUR, LOW)	TOTAL INSTALLATION COST (EUR, HIGH)
Topside installation	Large heavy lift 7000-14000t	5	600,000	4,600,000	5,600,000
Topside transport	North Sea Barge with two tugs	5	-	150,000	160,000
Jacket transport and installation	Large heavy lift 7000-14000t	4	300,000	4,3000,000	5,100,000
Foundation transport and installation	Construction 400-1000t	6	50,000	900,000	1,100,000
Installation cost per platform			950,000	9,950,000	11,960,000

Table 3-6: Overview of installation costs for installing a topside, jacket and piles of an offshore hydrogen production platform

Integrated concept
Hydrogen production at each turbine assumes a modular installation using 40 ft. containers to house the hydrogen production equipment. Each turbine will have a deck where containers can be placed as indicated in section 3.5. Installation of containers on the turbine deck is done by a light construction vessel which can hold approximately 14 containers, enough to equip 2 turbines (15-20 MW). A distance of 100 km is again assumed to provide a reference for the installation costs. The costs are indicated in Table 3-7.

Similar remarks should be made as for the installation of a platform, that there is still a degree of uncertainty regarding vessel types, rates and the overall installation method. Due to the novelty of offshore hydrogen production, there is no detailed design or common practice.

Shorter or further distances also have an impact on the installation costs as the duration of transit will increase. Distances of 50, 200 and 300 km lead to a difference of -5%, +12% or +24% (respectively) compared to the installation costs for 100 km distance.

COMPONENT	VESSEL TYPE	TOTAL DURATION (DAYS)	ONSITE INSTALLATION COST	TOTAL INSTALLATION COST (EUR, LOW)	TOTAL INSTALLATION COST (EUR, HIGH)
14 x 40 ft. container with process equipment (enough to equip 2 turbines)	Light construction vessels 50-250t	2	negligible	140,000	190,000
Installation cost to equip 1 turbine (15-20 MW, 7 x 40 ft. containers)			**negligible**	**70,000**	95,000

Table 3-7: Overview of installation costs for installing a container on a turbine

3.6.2 MAINTENANCE

Offshore maintenance will provide additional challenges as accessibility of an asset is more difficult offshore than onshore. Offshore O&M vessels are needed to access the asset, transit times take longer, crew requires more training and weather conditions add even more challenges. To estimate O&M cost figures these aspects should be considered as well as an O&M strategy. Such a strategy has not yet been developed as offshore hydrogen production is still conceptual. In addition, the application of electrolysers offshore is still a topic for development, further research and optimization. Increased O&M costs could drive adaptations to the electrolyser design which will reduce O&M needs (while CAPEX might increase).

Currently, typical electrolyser maintenance includes weekly to monthly inspections and scheduled maintenance each 6 months or each year. Further development could lead to an inspection and maintenance requirement only once a year which will reduce the O&M costs. Further experience is required to evaluate the need for corrective maintenance. Currently there is only little operational experience with the newest generation electrolysers as well as an electrolyser directly coupled to wind power. An O&M strategy should also include further assessment if the offshore asset will be manned or unmanned. This topic extends beyond cost optimization but also includes safety aspects which are still unknown. This will be especially valid for centralized hydrogen production on a platform.

As an advantage, synergies between O&M of the wind farm and the electrolyser could provide opportunities for combined O&M campaigns. Especially with the integrated concept, maintenance to the turbine can be combined with maintenance to the electrolyser.

Offshore maintenance of electrolysers is still a topic for further research and more detail would be required to estimate sensible cost figures.

3.7 Array pipelines

With decentral offshore hydrogen production, where hydrogen is produced directly at the turbine, the role of conventional array cables is taken over by array pipelines. The pipelines transport and collect the hydrogen throughout the windfarm and connect to a larger manifold or to an export pipeline.

The costs for such array pipelines were assessed in a study led by DNV to compare different topologies and the use of different materials (steel and composite materials) in a specific use case. The exact details and findings of the study are confidential but the anonymized and generalized details can be used in this study.

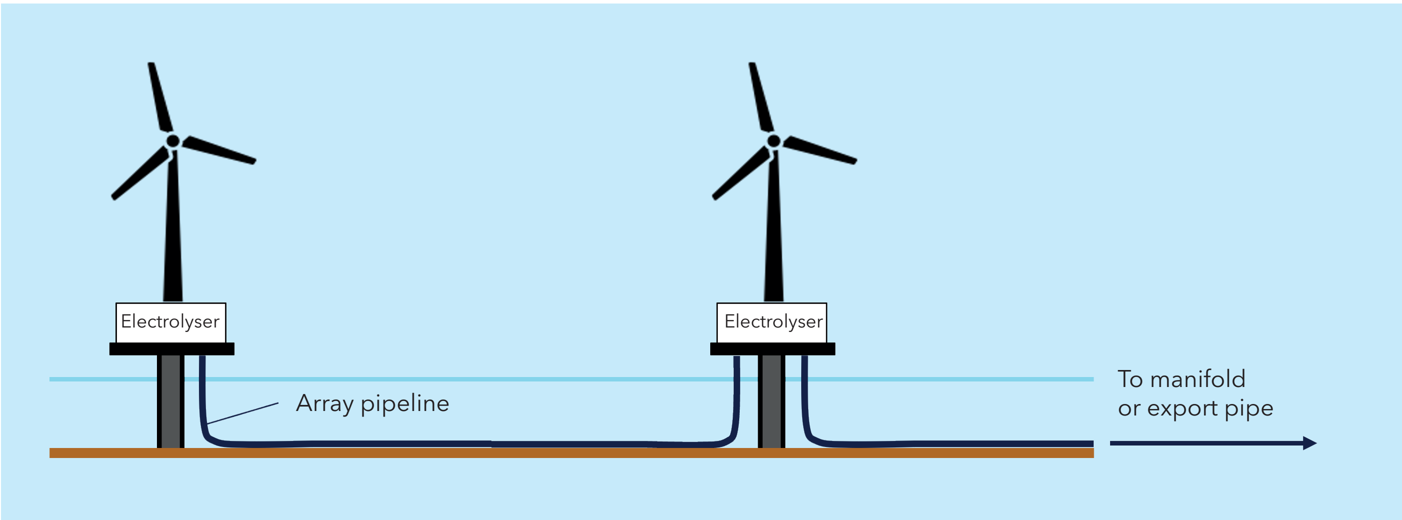


Figure 3-10: Interconnection of hydrogen producing turbines with array pipelines (daisy chain configuration)

The study included the following assumptions and cost aspects:

- Turbines of 17 MW with a hydrogen production of roughly 3,200 Nm³/h
- A water depth of 45 m and a spacing between turbines of 2 km
- Assessed a partial wind farm (20 turbines) but assumed an infinite capacity for the complete wind farm (this has an effect on costs)
- Approximately 100 km from shore in the North Sea
- The pipes are operated at 30 bar[2] and have a diameter ranging from 2" to 6"
- The assessment includes the costs for

MATERIALS	INSTALLATION
– Pipes – Connection pieces and valves – Sub-sea equipment – Etc.	– Vessel costs including crew – Transit times including typical North Sea weather window for installation (and associated costs) – Installation time for connecting, welding, inspection, etc. – Costs for mobilization and demobilization of vessels – Preparation, trenching and engineering

- Costs based on current figures (2022)

The complete Capex for the array pipes that interconnect 20 turbines was found between 20-30 MEUR depending on the selected concept. Approximately 30-50% of the costs are for installation. The maintenance costs are estimated at 0.5% of Capex per year.

As this was a case study based on a fictional case, the results should be considered high level (approximately 50% certainty). A detailed sensitivity analysis was not performed, and it is uncertain what costs will be found in different use-cases. Turbine capacity, number of connected turbines, wind farm lay-out, distance to shore, the availability of ports and vessels and the effect of the weather will likely have a large impact on the costs. The lack of real-world application experience (novelty of concept, application with H_2 production) brings additional uncertainty. The costs are based on current cost figures and at this stage it is unclear what (cost) developments can be expected. This will largely be influenced by technological development but there is also a strong relation to vessel rates, their availability (large demand can be expected with large scale roll out of offshore wind) and fuel prices.

The information above provides a cost reference which can be used to derive the following formula.

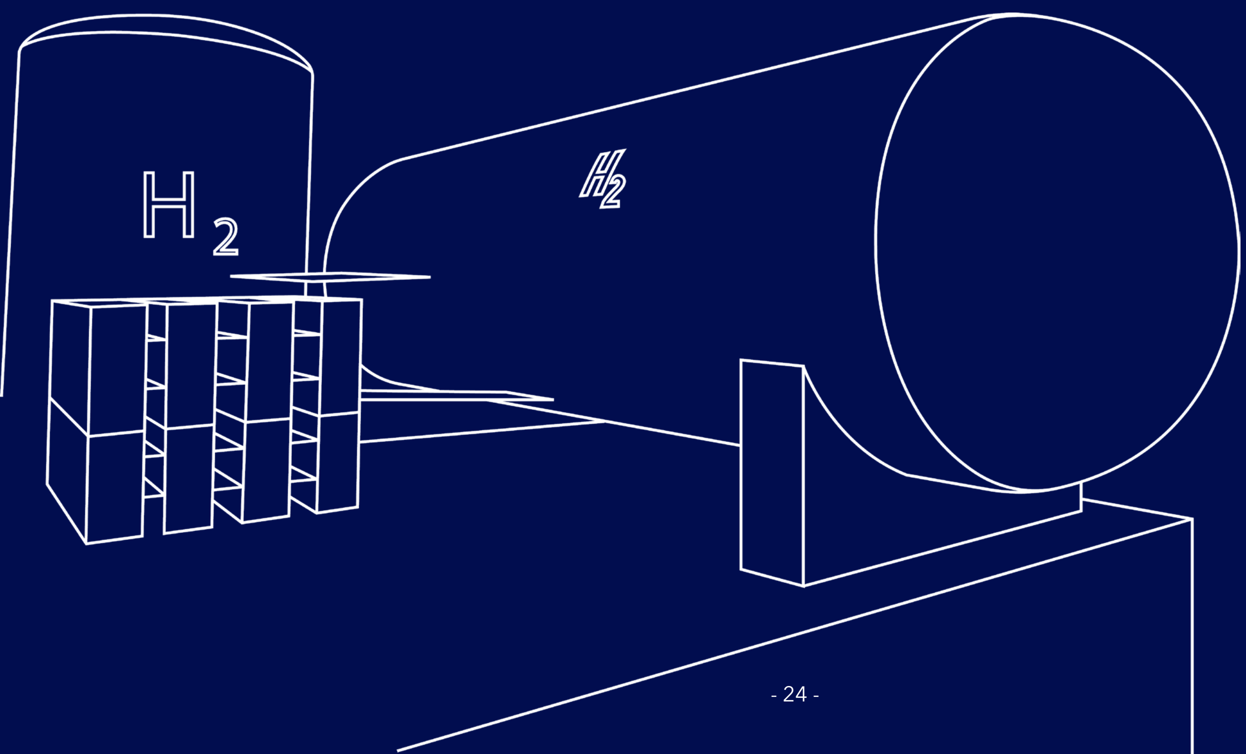
Array cables vs array pipes

As a reference DEA provided cost figures for array cables. Assuming 500 €/m for array cables, a spacing between the turbines of 2 km and a turbine capacity of 17 MW, provides a cost estimate of approximately 60 kEUR/MW ((500*2000)/17). This is in the same order of magnitude as the cost figures for the array pipes.

$$\text{Capex of array pipes (kEUR)} = \text{wind farm capacity (MW)} * 75 \qquad (13)$$

[2] The electrolysers will have an output pressure of 30-40 bar. A centralized compressor can further increase the pressure for exporting the hydrogen. Alternatively, each turbine can be fitted with a compressor but this could have disadvantages in terms of O&M, economies of scale and reliability. A higher operating pressure of the array pipes will have an increasing effect on costs, but this is limited and within the uncertainty of the provided figures.

4. REFERENCE CASE



4. REFERENCE CASE

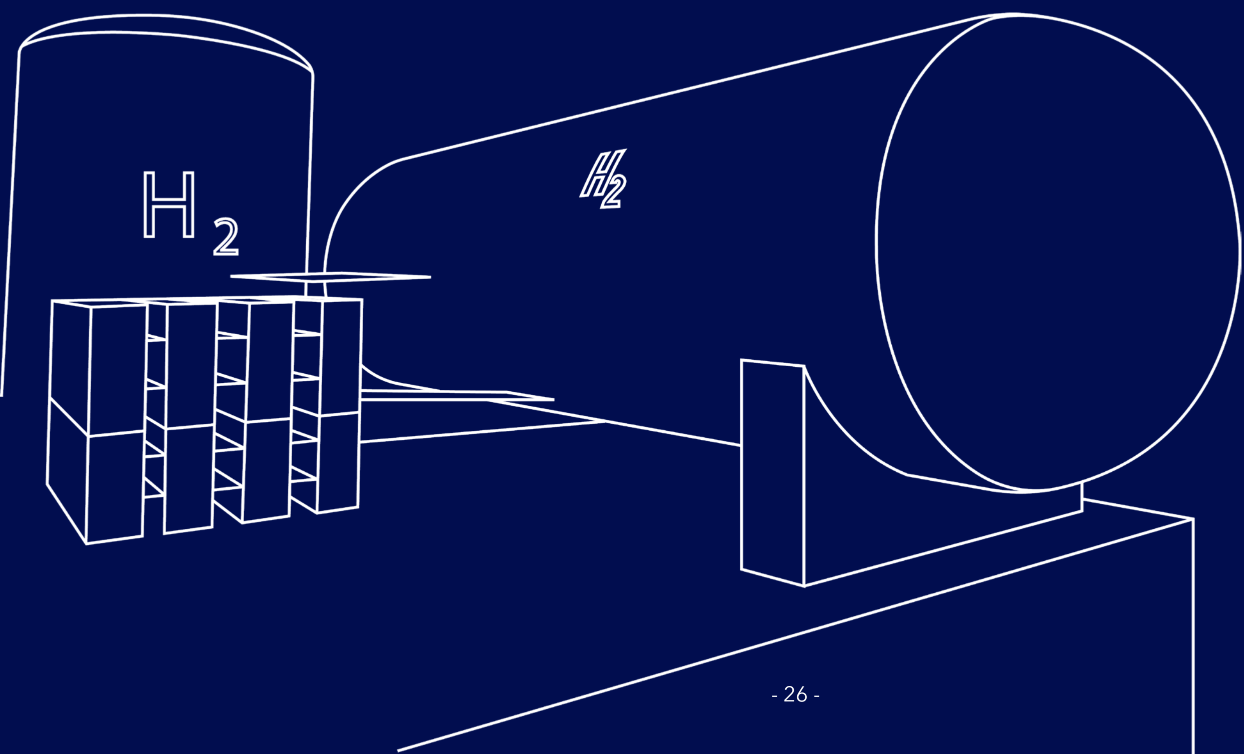
The cost figures and formulas provided in the previous sections are applied to reference cases to provide an example and to allow for checking calculations. The cases consider:

1. The integrated concept. A single 15 MW wind turbine withhydrogen production equipment of the same capacity and array pipes.
2. Platform concept. A 500 MW platform with hydrogen production equipment.

Both cases consider a water depth of 40 m. The results are included in the table below.

	CAPACITY	MASS (TONNE)	AREA (M^2)	SYSTEM COST	INSTALLATION COST	TOTAL	SOURCE
Integrated electrolyser/turbines (2030)							
Turbine	15 MW			Not included	Not included	**Not included**	
Turbine structure *Working platform* *Jacket* *Foundation*	Based on weight	 *147* *1,694* *750*		7,986.098 *1,102682* *5,758,580* *1,124,836*	Not included	**7,986,098**	 Formula 7&8 Formula 9&10 Formula 11&12
Electrolyser (pressurized alkaline) *Stacks* *Distance of plant*	15 MW		450	6,869,366 *3,668,130* *3,201,236*	3,434,683	**10,304,050**	Table 3-2 Figure 3-3 Formula 2
Water treatment and cooling	Based on electrolyser capacity		15	195,000	19,500	**214,500**	Table 3-3
Installation of equipment on turbine	1	Turbine (15 MW ref)			95,000	**95,000**	Table 3-7
Array pipelines	1	Turbine (15 MW ref)		562,500	562,500	**1,125,000**	Formula 13
Controlled hydrogen production platform (2030)							
Turbines	500 MW			Not included	Not included	**Not included**	
Array cables (66 kV)	500 MW			Not included	Not included	**Not included**	
Transformer	500 MW	433		16,550,000	4,965,000	**21,515,000**	Table 3-1
Electrolyser (pressurized alkaline) *Stacks* *Distance of plant*	500 MW	4,250		147,017,194 *102,607,601* *44,409,593*	73,508,597	**220,525,792**	Table 3-2, Formula 1 Figure 3-3 Formula 2
Water treatment and cooling	Based on electrolyser capacity	250		6,500,000	650,000	**7,150,000**	Table 3-3
Platform structure *Topside structure* *Jacket* *Foundation*	Based on weight	 *4,933* *4,494* *871*		53,580,003 *36,993,750* *15,279,104* *1,307,150*	11,960,000 *5,760,000* *5,100,000* *1,100,000*	**65,540,003**	 Formula 3, Table 3-7 Formula 4&5, Table 3-7 Formula 6, Table 3-7
Additional reference: 15 MW turbine structure without hydrogen production (2030)							
Turbine structure *Working platform* *Jacket* *Foundation*	Based on weight	 *31* *1,694* *750*		7,114,223 *230,807* *5,758,580* *1,124,836*	Not included	**7,114,223**	 Formula 7&8 Formula 9&10 Formula 11&12

5. BIBLIOGRAPHY



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