Design of an Electrolyzer Integrated in an Offshore Wind Turbine System

PDEng Thesis

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Executive Summary

In this PDEng, a conceptual design of an electrolyzer integrated with an offshore wind turbine to produce 'green' hydrogen was developed. In the concept, the electrolyzer, heat management, purification and desalination systems are integrated onto an enlarged external platform located at the transition piece of the turbine substructure.

Design Approach

The design process was divided into 3 main phases: First, a preliminary system design, following a system engineering approach, was performed to identify functions and requirements, select technology, define logical system architectures and identify interfaces between the systems. Next, a system integration analysis was made to assess further the technical feasibility of the preliminary system design concerning operational flexibility, physical & electrical integration and to generate and select potential integration concepts. Finally, an economic assessment is performed to determine the benefits of the integration in terms of the Levelized cost of hydrogen (LCOH).

Preliminary System Design

The main design choices made during the preliminary system design process were:

- The base case for the design is a 15 MW reference offshore wind turbine operating in a typical North Sea climate that is part of a larger offshore wind farm.
- PEM electrolysis was selected for the design as the preferred technology for the integration due to its superior characteristics (compared to alkaline electrolysis) in terms of reduced footprint, high operational flexibility (operational response and range), and output pressure.
- The current quality of the produced heat from the electrolysis process is insufficient to use it to drive thermal desalination reliably. Therefore, the excess heat is drained into the environment by using seawater cooling.
- Reverse osmosis was selected as the preferred option for water desalination. This technology was seen as advantageous with respect to other technologies in terms of reduced footprint and higher energy efficiency. However, due to the low flexibility of the reverse osmosis system, integration with the wind turbine-electrolysis system required the addition of a buffer tank to manage the fluctuations in water demand and power supply.
- Compression at a centralized collection point in the vicinity of the wind farm is selected as the preferred option to transmit the produced hydrogen to shore. The pressure of the produced hydrogen is sufficient to transfer it from the turbine to the centralized collection point from which the pressure of hydrogen is further raised to transmit the hydrogen to the shore.
- A reciprocating (oil-free) compressor was selected as the preferred technology to raise the pressure of the produced hydrogen at the centralized compression point. In this case, to handle the maintainability drawbacks of reciprocating compression technology, an arrangement of at least 2 compressors, each sized to handle 50 % of the hydrogen-wind farm production plus one spare compressor (also sized for 50 % production), is suggested.

Integration Analysis

The power production of a 15 MW reference turbine with respect to the operational flexibility of current industrial PEM electrolyser systems was analysed. The main results from this analysis are:

- The turbine maximum power step changes at rated, below rated, and low power scenarios are <1.5%/s and <9,7 %/s when assessed with IJmuiden and an IEC Class B wind profiles, respectively. Both power ramp rates fall below the maximum ramp rates of industrial PEM electrolysers(~10%/s), implying that current PEM electrolyzers are suitable for turbine integration.
- During low wind speed periods, the limited power production of the wind turbine could result in the electrolyzer operating below the minimum safety threshold. Therefore, a decision was made to split the electrolyzer system into three independent modules, each with a 5 MW capacity. This modularization, combined with a control strategy, allows a reduction in the minimum operational threshold and thus the safe operation of the electrolyzer system.
- Operation close to the turbine's cut-in wind speed results in short-term gaps in power production that still fall below the safety threshold of the modularized system. In this case, energy buffering with supercapacitors is proposed to avoid operation in unsafe scenarios.

To analyse the physical integration of the electrolyser system, sizes of the main components within the system were estimated. The resulting footprint reduction opportunities, compared to current onshore electrolysis system, were identified:

- The use of sea water plate heat exchangers results in a compact cooling system to remove the excess heat of the electrolysis process
- The main opportunity for footprint reduction in the electrolyzer's balance of plant is the scaling up of oxygen gas-liquid separators. However, to maintain the system's modularity, the equipment scaling up was limited to handle the capacity of electrolysis modules up to 5 MW.
- The relatively high voltage ratio between the turbine generator and the electrolyzer modules suggests that a step-down transformer is still required for integration. However, these have a high additional footprint, and thus the use of high-frequency transformers (e.g. 400 Hz) is suggested to reduce this impact.
- Finally, further footprint reduction could be attained by moving the hydrogen purification step from the integrated electrolyzer-turbine to the centralized collection point.

The added mass of the complete electrolysis system was roughly estimated to be in the order of 300 tonnes. This mass was subjected to a natural frequency check, which showed that no impact is expected when the electrolyzer system is placed at the lower sections of the turbine structure (such as the tower base or the transition piece).

To reduce the complexity of the offshore installation process, this study recommends that the electrolyzer be combined with the transition piece onshore. The combined system would then be installed offshore as per traditional installation methods. The added weight is shown to be within the capabilities of the required transportation equipment.

Two integration options were explored for the combined system: internally within the transition piece or on an enlarged external platform surrounding the transition piece. The options were compared in regards to maintainability, inherent safety, required structural modifications and offshore installation impact, from which the external integration option was chosen.

Economics

The Levelized Cost of Hydrogen (LCOH) was estimated for two cases: offshore hydrogen production and onshore hydrogen production. In the first case, hydrogen is assumed to be produced at the turbine and transmitted to shore via pressurized pipelines. In the second case, it is assumed that electricity from the wind farm is transferred via export cables to shore, where it is then directly converted to hydrogen. Both cases were assessed using the current state of the art technology and electrolyzer costs and assuming that the produced hydrogen is injected pressurized in the gas network. The results showed cost advantages for the offshore case compared to the onshore as the energy for hydrogen production can be supplied at higher efficiency and lower transportation cost. However, this cost advantage is mildly reflected on the estimated LCOH for the offshore (4 €/kg) with respect to the onshore (4.2 €/kg) due to the much higher cost contribution from other components in the system, such as the CAPEX and OPEX of the turbine and the electrolyzer.

The two cases were analysed in a near-future scenario (2025) in which the Capex and energy efficiency of the electrolyzer are expected to be improved. Under this scenario, the minimum LCOH was estimated to be 3.4 €/kg for the offshore case. At the moment, the estimated LCOH is still not cost-competitive with the current cost level of grey hydrogen (<2€/kg) for large-scale applications (such as refineries and fertilizer plants). However, the estimated production price of green hydrogen may be competitive with potential emerging markets, such as heavy-duty mobility, where higher prices are expected (5-7€/kg at the point of consumption). It should be noted that the calculated LCOH does not incorporate incurred costs after the hydrogen is delivered to shore from the wind farm. Therefore, the LCOH is expected to be higher at the point of consumption.

Conclusions

The main conclusion of the design process is that integration of the electrolyser system is technically possible with existing technologies, and at this stage of development, no technical limitations were found.

From an economic point of view, the LCOH of green hydrogen is, at the moment, still higher than the grey one. However, the integration of offshore wind and electrolysis, combined with modest innovations in the 2025 scenario, offers the possibility of closing this gap more and more. Moreover, the market and the need for more sustainable ways of producing hydrogen and decarbonizing the industry exist today. Thus, it is just a matter of time before green hydrogen becomes the dominant type of hydrogen in our society.

Acronyms

AEM Anion Exchange Membrane
AKN Alkaline Electrolysis
BOP Balance of Plant
EHC Electrochemical Hydrogen Compressor
LCOE Levelized Cost of Electricity
LCOH Levelized Cost of Hydrogen
MCA Multi-Criteria Analysis
MED Multi-Effect Distillation
MSF Multi-Stage Flash Distillation
MVC Mechanical Vapour Compression
PE Power Electronics
PEM Proton Exchange Membrane
PFD Process Flow Diagram
RO Reverse-Osmosis
SOEC Solid Oxide Electrolysis Cell
SME Subject Matter Expert
SMR Steam Methane Reforming
TVC Thermal Vapour Compression
TSO Transmission System Operator
OWF Offshore Wind Farm

1 Introduction

1.1 Project Overview & Motivation

In 2016, in the Paris Agreement, a set of targets that the world needs to pursue to limit our current impact on the environment were established. As an essential point, these targets require substantial CO_2 emissions reductions across all sectors [1].

In the electricity sector, renewable energy technologies (such as wind & solar) are main options to reduce the required emissions. In particular, offshore wind is an abundant source of energy with increasing momentum worldwide. The IEA[1] estimates that offshore wind energy's technical potential is more than 120000 GW worldwide, from which near 420000 TWh of electricity could be produced per year [2]. Therefore, the offshore wind industry is expected to further expand in the coming years, with new sites being built even into farther and deeper seas.

On the other hand, future sustainable energy systems scenarios indicate that hydrogen can play an essential role in our society. In particular, converting renewable energy to hydrogen via electrolysis opens opportunities to reduce our electricity's carbon footprint and expand the share of renewable energies to other industrial sectors where electrification is either difficult or not possible (e.g., a feed-stock and energy source in the industry) [3]. There is also a possibility to store the energy when a surplus of renewable energy is produced.

Although offshore wind and hydrogen from electrolysis undoubtedly have a role in helping achieve our societal goals, their further expansion comes with new challenges. For example, at farther distances from shore, the business case of offshore grid-connected turbines starts becoming uneconomical due to the rapid increase in connection costs [4]. Besides, as the share of intermittent energy sources continues to increase, it is expected that the limits of fully electrical connection will be reached [5].

On the other hand, hydrogen production via electrolysis is currently not cost-competitive with hydrogen from fossil sources. In particular, one of the highest cost contributors of electrolysis based hydrogen is the cost of renewable electricity [6]. This issue is partly due to the multiple intermediate conversion steps (needed to transmit the energy from generation to consumption) that result in additional energy losses and costs before the energy can effectively be transformed into hydrogen.

From the previous issues, it is clear that further efforts are needed to successfully integrate hydrogen and offshore wind into our energy system. In this regard, a concept that is currently gaining attention is the integration of electrolyzers with offshore wind turbines in a single system. This integration offers potential advantages over the traditional individual systems as follows:

• **Potential reduction costs of transporting energy from offshore**. Hydrogen transport through pipelines could provide a cheaper alternative for transporting energy as more significant amounts of energy can be transported per unit of volume [3, 7, 8].

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[1] IEA: International Energy Agency

• **Potential function of pipelines as a storage medium.** Hydrogen in long transmission pipelines can potentially serve as a buffer media by reducing or increasing their pressure. In this way, it is possible to increase the system's flexibility to help balance supply and demand [7].

• **Potential avoided conversion losses.** Integration of the electrolyzer and the turbine generator potentially avoid the electrical conversion and transmission losses in the power lines and offshore/onshore substations between the turbine generator and the connection point inland [9].

• **Potential reduction of grid congestion and increase of energy production.** In high wind periods, the excess energy production of a wind farm is often curtailed to protect the electrical grid from saturation. This curtailment reduces the energy production of the wind farm and thus negatively impacts its business case. In this regard, hydrogen offers further flexibility to accommodate energy production with the demand by hydrogen storage [7].

• **Potential expansion of offshore wind energy to other markets.** In the future, the excess of renewable energy in the market could destabilize energy prices. Hydrogen offers the possibility to expand the reach of offshore wind energy to additional markets, including those in which electrification is not possible [1, 3, 10]

• **Potential extended usage of the oil & gas platforms**. In the North Sea, several offshore oil and gas platforms are reaching the end of life. In this context, large scale green hydrogen production could benefit from the existing gas infrastructure to reduce the cost of transporting energy to shore [11, 12]

• **Potential decrease of the hydrogen production cost from renewable sources**. For example, direct coupling of wind energy and electrolyzers could provide cost reductions by eliminating intermediate steps and then energy transfer between the system and providing the electrolyzer access to the Levelized cost of electricity (LCOE) [13].

1.2 Project Stakeholders

This PDEng project was performed at the Energy Transition Unit of the Netherlands Organisation for Applied Scientific Research (TNO), whose ambition is to accelerate the energy transition and strengthen the competitive position of the Netherlands.

As part of its research & development program, TNO seeks to reduce the production cost of green hydrogen, as it could serve as an energy vector for the decarbonisation of the industry. In this regard, TNO holds a strong position in developing, testing, and upscaling electrolysers and research and development within the wind industry. As a result, TNO’s is currently investigating the potential benefits of directly coupling electrolysers to wind turbines (thus avoiding intermediate conversion steps) for which this PDEng project was created.

This PDEng project is performed in collaboration with the University of Twente (UT), whose main mission is to empower society through the development of sustainable technology solutions. For this mission, the UT, through its PDEng program, educates designers capable of addressing complex technological issues. The PDEng program is a 2 year post master program, in which the second year is focused on a technological design as the one this report documents.

1.3 Design Issue

The design issue addressed in this PDEng is the complexity of integrating two (and more) systems (offshore wind & electrolysis) that are very different by nature and require knowledge in several disciplines. The renewable wind production system is an intermittent source of energy that is primarily dependent on weather conditions. In contrast, although flexible, electrochemical systems (such as hydrogen electrolysis) are typically operated under controlled conditions. Therefore, experience needs to be built up with variable/intermittent operation.

In addition, to date, hydrogen electrolysis systems have not been tested in offshore environments, where space, resources limitations (such as access to purified water and heat), more complex maintenance operations, among others, need to be considered.

Although both technologies do exist, they are still in the phase of development. In particular, for hydrogen electrolysis, significant upscaling (in size and market volume) and cost reduction are needed. Moreover, as the design is applied to an unfamiliar operational environment, several uncertainties are involved, especially to maintain a safe and reliable system operation.

In a preliminary TNO[2] study, the potential benefits of this concept have been suggested [7]. However, a conceptual design is needed to understand better these benefits and potential limitations of the integrated system.

Some research questions at the system level in this project are:

- What are the current technological limitations for system integration?
- How do the different components within the designed system interact, and what are their interfacing requirements?
- What are the techno-economic potential gains of the integrated system?
- Which are the potential new requirements in terms of installation, operations & maintenance derived from the integrated system

1.4 Project Goal

This PDEng project aims to develop a conceptual system design of an electrolyzer integrated with an offshore wind turbine. The integration is conceived for a bottom-fixed horizontal wind turbine of 15 MW capacity (as a state of the art size) for a typical North Sea climate.

To accomplish this goal, the following approach is followed:

- To develop a system architecture of the envisaged integrated system
- To develop system models to assess the performance of the integrated system
- To assess potential techno-economic gains and limitations of the integrated system
- To optimize the system concerning size, integrated power electronics and physical structure.

[2] In collaboration with other companies

1.5 Design Scope

Figure 1 depicts a top view block diagram as a starting point for the system concept [7]. This figure shows that the basic building blocks to produce hydrogen via electrolysis are water and electricity. The water is produced from a desalination unit, whereas an offshore wind turbine supplies the electricity. The produced hydrogen gas is then transferred to a central collection point that further dispatches the hydrogen to the shore through a transmission system or ships.

The scope of this PDEng study focuses on the conversion of offshore wind energy to hydrogen through the integration of an electrolyser into a wind turbine. As shown in Figure 1, the design limits include water desalination, energy production, hydrogen conversion and further transfer to an offshore collection point. The design includes potential modifications to a state-of-the-art offshore wind turbine in a typical North Sea climate as part of a larger wind farm. The wind farm design (Wind Turbine choice, locations and the collection system) are not part of the assignment

Although the design primarily focuses on a single turbine electrolyzer system, the wind farm context in which the system operates is considered for the design.

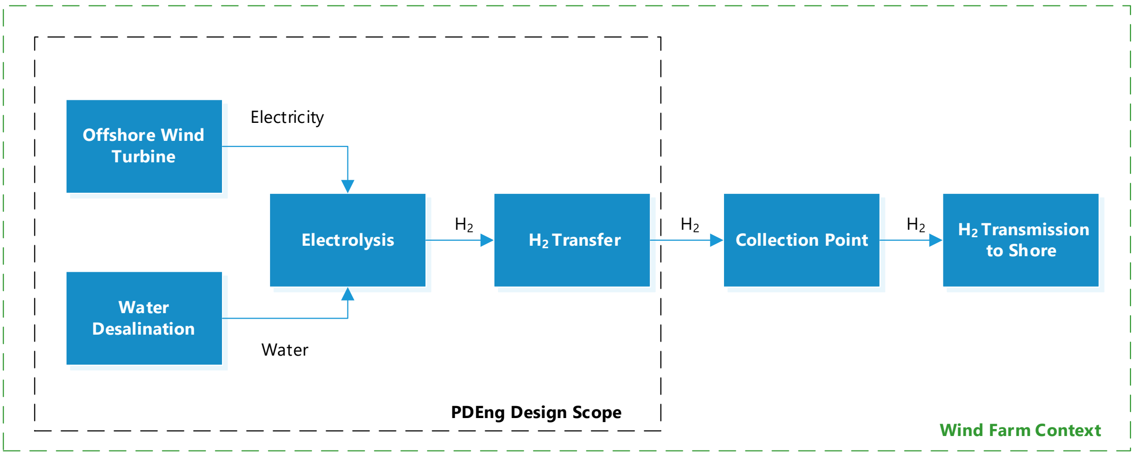

Figure 1 Offshore Wind Turbine-Electrolyzer Integration Overview.

1.6 Report Outline

Chapter 1 introduces the topic and context of the PDEng project, the stakeholders, the design issues and the main goal of the design. Chapter 2 describes the methodology used to approach the design issue. Chapter 3 contains literature covering the hydrogen market, technical characteristics, and background information regarding offshore wind and electrolysis systems. Chapter 4 deals with the development of system specifications and the generation of a preliminary system design following a top-down approach and principles of the system engineering methodology. Chapter 5 is dedicated to assessing the technical feasibility of the integration. This is presented by analysing the operational compatibility of the wind turbine and electrolyzer system and estimating sizes & weights for physical & electrical integration. At the end of the chapter, two potential integration concepts are presented, and a concept selection is performed. Chapter 6 summarizes the economic assessment performed to determine the levelized cost of hydrogen of the integrated system for current and future scenarios. Chapter 7 reflects on the design process and the fulfilment of the requirements. Finally, Chapter 8 summarizes the main conclusion of the design process and provides some recommendations for future stages of design.

2 Design Methodology

As mentioned in the previous section, the main goal of this PDEng project is to generate a conceptual design of an electrolyzer integrated with an offshore wind turbine system. For this aim, the design methodology described in the following sections is pursued.

2.1 Design Cycle & Systems Engineering

The design methodology of this PDEng project follows a traditional engineering design cycle (shown in Figure 2), complemented with methods from the Systems Engineering approach.

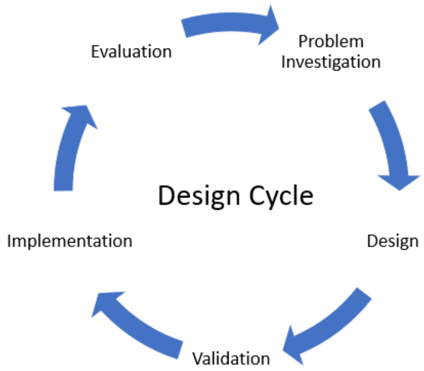

Figure 2 Engineering Design Cycle. Adapted from [14]

The reason to use system engineering techniques is due to the high level of complexity expected in this design, resulting from the number of subsystems and the different disciplines involved in the project (such as offshore wind, electrolysis, desalination, gas compression, power electronics, among others). Figure 3 illustrates the typical activities in the system engineering process, including requirement analysis, functional analysis, and synthesis.

Note that like in the design cycle, systems engineering is an iterative technique requiring validation and verification loops.

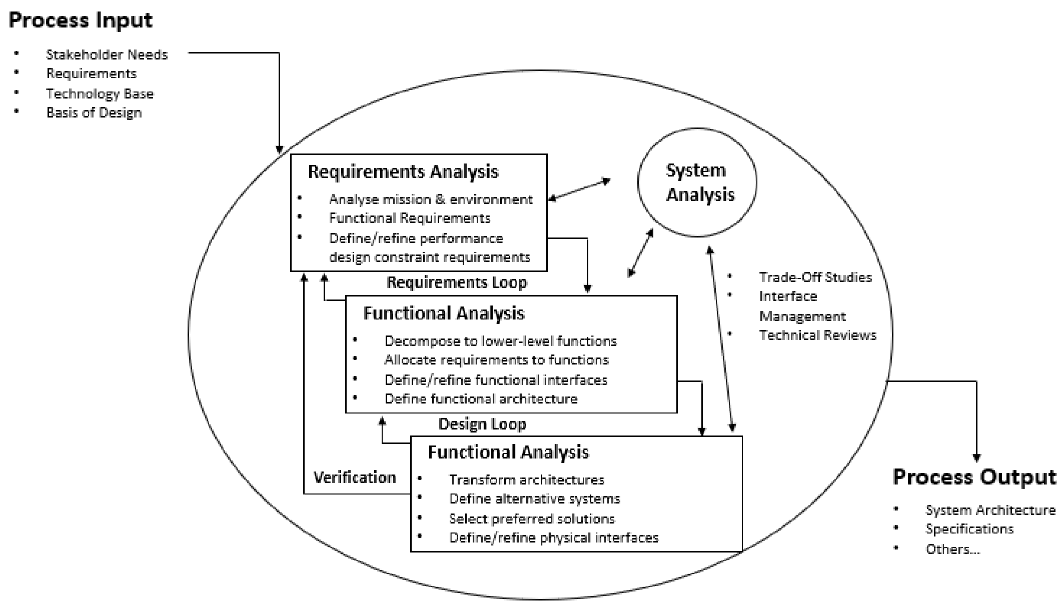

Figure 3 Systems Engineering approach. Adapted from [15]

Figure 4 shows a simplified version of the three main phases followed during the design process in this study. A more detailed division of the design methodology used in the PDEng is shown in Figure 39 in Appendix A.

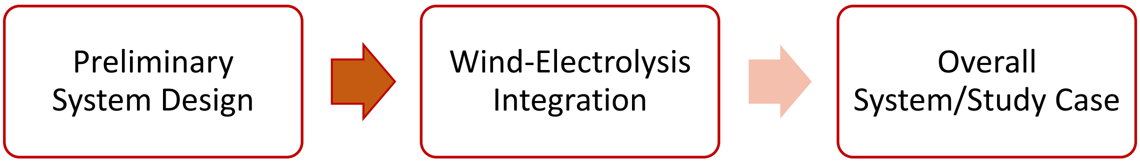

Figure 4 Simplified Design Approach

Preliminary System Design*:*

In this phase, the design problem is investigated, the primary function that the system needs to perform and requirements at the system level are identified. The identified functions and requirements are allocated to specific technologies based on technical analysis and trade-off studies. As a result of this phase, a preliminary technology selection and preliminary system architecture is generated.

System Integration Analysis*:* This phase investigates the technical feasibility of the preliminary design concerning operational flexibility physical and electrical integration. At the end of this phase, potential integration concepts are generated, and an analysis to select the most suitable concept is performed.

Overall System/Study Case*:* In this phase, the refined design is analysed by performing a case study of application for the Netherlands. The case study runs mostly on economic analysis to determine the benefits of the integration in terms of the Levelized cost of hydrogen (LCOH).

2.2 Validation Methods

This PDEng project uses two main methods to validate the design decisions: expert opinion and through modelling and simulation of specific parts of the system.

Expert opinion validation is performed with technical experts from TNO, the University of Twente and product vendors. This validation helps as decision support to understand the pros and cons of particular alternatives based on experience and thus limit the number of design solutions.

In addition, validation is performed by approximating the system (or parts of the system) behaviour through numerical modelling. Depending on the specific item to validate, different types of models are used. These models include engineering models to describe process & electrochemical performance of the PEM electrolysis system and tools such as OpenFAST[3] to capture specific characteristics of the turbine.

[3] OpenFast is an open-source wind turbine tool for simulating the coupled dynamic response of wind turbines

3 Literature Review

In this chapter, the current status and future market opportunities of hydrogen are reviewed. Next, an overview of the technical characteristics and advances in offshore wind and electrolysis systems is presented. From the previous overview, an analysis of the applicability of the different electrolysis technologies for offshore integration is discussed. Then, the implications of the dynamic operation of the system and derived safety aspects are discussed. Finally, an overall description of recent offshore wind - electrolysis integration projects is given.

3.1 Hydrogen Market: Status & Opportunities

3.1.1 Production

Nowadays, hydrogen is mainly obtained from dedicated fossil-based production facilities located close to its demand. As shown in Figure 5, the most extended hydrogen production methods are steam methane reforming (SMR) and coal gasification. The selection of one method over the other is mainly a function of the price difference of feed-stock between regions [1, 3].

Figure 5 also shows that to a lesser extent, hydrogen is also obtained as a by-product of industrial processes such as catalytic naphtha reforming, steam cracking, chloro-alkali, whereas the contribution of hydrogen produced by renewables is almost negligible.

3.1.2 Uses

In 2018, 120 M tonnes of hydrogen were produced in the world [1, 10] . From this production, pure hydrogen reached a market demand of around 73.9 M tonnes. As shown in Figure 5, this demand comes mainly from the fertiliser (ammonia production) and the refining industry (hydrocracking and fuel desulphurisation). Lower contributions to the pure hydrogen demand result from the chemicals, metals, electronics and glass-making industries. On the other hand, hydrogen mixed with other gases achieved a market demand of about 42 M Tonnes. The primary use of mixed hydrogen is for the direct production of methanol, direct reduction of iron (DRI), and as a heat source [3].

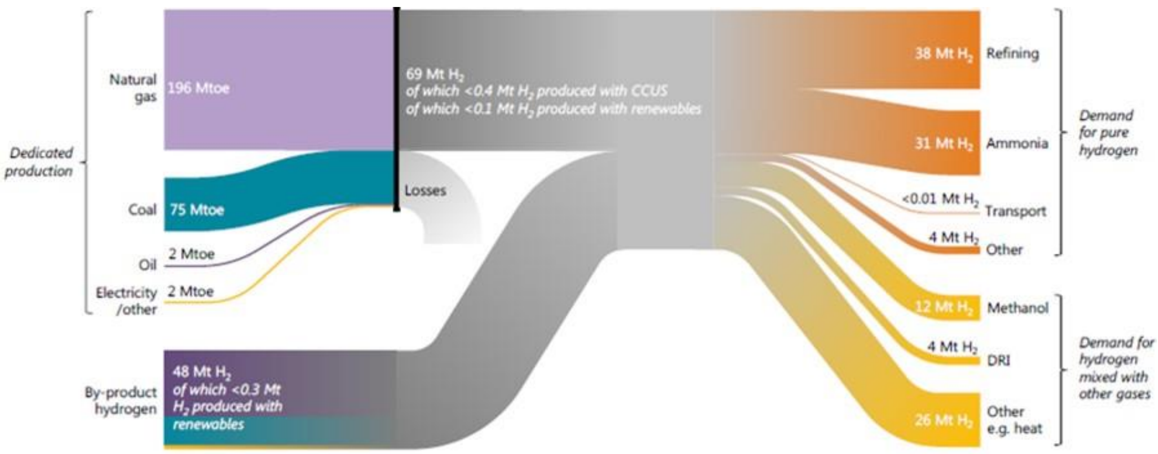

Figure 5 Current Hydrogen Value Chain. Reproduced from IEA 2019

3.1.3 Carbon Footprint

Currently, hydrogen derived from fossil fuels is responsible for around 830 Million Tonnes of CO_2 per year [3]. From the two most extended production methods, coal gasification has higher emissions than steam methane reforming (SMR), with around 22.5 and 9.5 grams of CO_2 per Kg of H_2, respectively [3, 16]. The relatively high CO_2 emissions of the hydrogen produced by the previous processes attribute its name to grey hydrogen.

A potential technique to reduce the emissions of fossil-based production techniques is a process called Carbon Capture & Storage (CC&S). In this process, the CO_2 emissions of the fossil base methods are captured and stored somewhere else. The resulting hydrogen, when CC&S is applied, is called blue hydrogen. Current CC&S projects achieve capture efficiencies below 33%, although efficiencies of around 85-95 % are expected for this technology in the future [3].

Finally, hydrogen produced via renewable electricity does not emit significant CO_2 emissions into the environment during operation as is generally called "green hydrogen".

3.1.4 Production Cost

In general, hydrogen derived from fossil fuel has a production price between 1 - 2 €/kg, and when carbon capture is included in the production cost, the price increases between 1.5 - 2.5 €/Kg [3, 4] . However, price variations are dependent on the market region, fossil fuel availability, volume demand, among others [3].

On the other hand, the production cost of hydrogen from variable renewable sources is highly dependent on the sun & wind availability. A comparison of the hydrogen production cost for different scenarios and sources performed by IRENA [10] is shown in Figure 6. This figure shows that significant cost reductions are required at electrolyzer CAPEX and electricity price to be green hydrogen competitive with fossil-based methods.

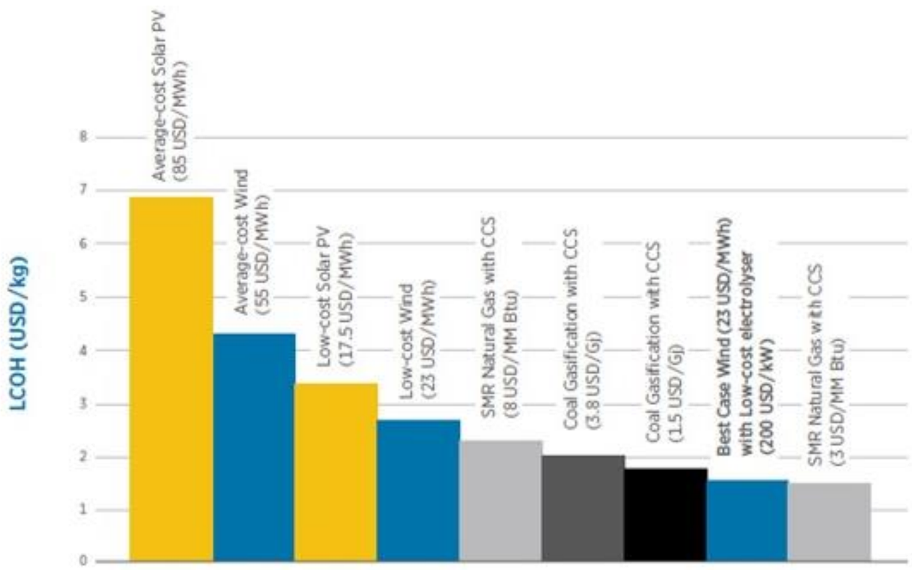

Figure 6 IRENA Estimated Renewable Hydrogen Levelized Production Cost (LCOH). Reproduced from IRENA 2019[4]

[4] Assumed electrolyzer CAPEX: USD 840/KW; Electrolyzer Efficiency: 85% ; Load Factors: 48% (wind) & 26% (solar)

3.1.5 Logistics & Transport

Nowadays, around 85 % of hydrogen derived from fossil fuels is produced near the demand site. The remaining 15% is transported via trucks or pipelines [3]. The potential integration of electrolyzed hydrogen with decentralized renewable energy sources implies that hydrogen would be transmitted and distributed over long distances. These new transmission requirements result in additional costs for the produced hydrogen that need to be considered.

Due to its relatively low volumetric energy density, hydrogen needs to be either compressed or liquified for its transportation. Hydrogen can be transported via pipeline, truck or ship media. Truck transport is practical for relatively small scales, whereas compressed hydrogen is used for distances below 300 km. For longer distances, cryogenic hydrogen has been transported in trucks for up to 4000 km.

As shown in Figure 7, providing significant demand, transporting compressed hydrogen in pipelines is cheaper than liquefying it for distances below 1500 km. However, for more considerable distances (intercontinental), hydrogen shipping in liquefied form would be more economical [10].

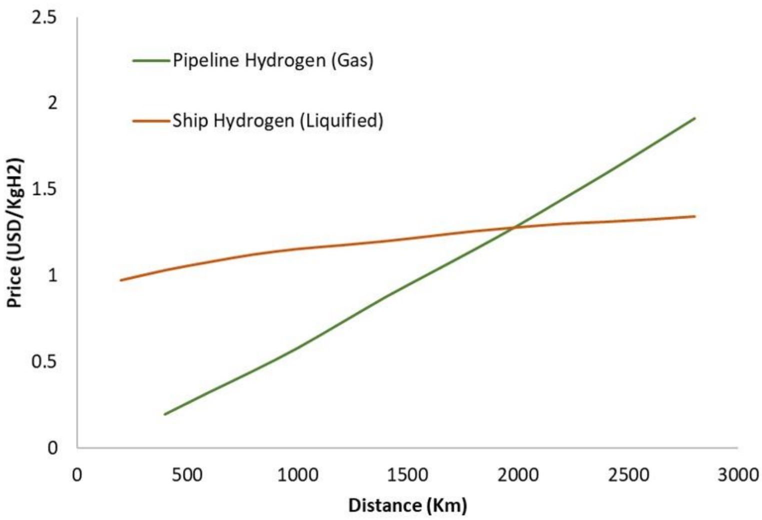

Figure 7 Hydrogen Transportation Prices as a function of distance. Adapted from IRENA 2019[5]

As an alternative for hydrogen transportation and direct use, the chemical conversion of hydrogen into synthetic methane, methanol, diesel, and ammonia is also an option. The energy transport as ammonia is much cheaper than direct hydrogen, either compressed or liquified form. However, compression, liquefaction or conversion to ammonia costs contribution needs to be added to the total cost of energy delivered (which can add around 1 USD/Kg H_2 to the price of delivered hydrogen [10]. Likewise, re-conversion costs (back to hydrogen) need to be considered if no direct use of the chemical compound is expected[6]. Therefore, selecting the cost-effective transport method is a function of the transmission geography, distance, scale and end-use.

[5] Hydrogen compressed at 100 bar. Liquefaction or compression costs are not included

[6] For LOHC, the carrier molecule needs to be returned to their place of origin at the end of the process

3.1.6 Green Hydrogen Market Opportunities

Green hydrogen is considered to play an essential role in the integration of renewable energies in society. This role can be achieved by expanding renewable energy's reach in sectors where electrification is not possible. Therefore, an overview of the future market perspective and the cost objectives for different sectors is given below.

Refineries

H_2 for refinery purposes is mainly used to remove impurities in the crude oil and upgrade heavy crude. It is expected that this sector will continue to be one of the primary markets for hydrogen demand [3]. Even though a decrease in hydrogen demand may result from a potential reduction of oil used in our society (derived from climate protection agreements), this decrease may balance out or even be overcome as a result of more strict regulations regarding the pollution limits (such as sulphur content) allowed in fossil-based fuels[7] [10].

According to IEA [3], several barriers need to be considered before green hydrogen can replace the current hydrogen production methods for the refinery industry. First, there are enough SMR facilities installed to sustain a potential rise in hydrogen demand. These units are expected to have a remaining lifespan of at least 20 years, with new projects still being constructed. Therefore, a shift to green hydrogen production would imply losses of these investments assets. Besides, with bulk production prices in the range of 1-2 €/Kg of H_2, this industry is very sensitive to prices changes due to the tight profit margins. Current production methods are typically located on-site and integrated with the refineries. Therefore, they avoid potential transmission and distribution costs resulting from producing hydrogen somewhere else. In this regard, alternatives such as CCU&S appear to be more cost-competitive than green hydrogen implementation in the short term, even though carbon prices above 50 €/per ton of CO_2 are needed to make CCU&S attractive in most of the regions [3].

Transportation Sector

Currently, the most significant technological progress falls in the road industry by using Fuel Cell Electrical Vehicles (FCEV). High purity hydrogen is required in this market as the power train used (fuel cell) is sensitive to the fuel pollutants. Furthermore, the suitability of hydrogen in the road transport sector is influenced, among other factors, by the type of use of the vehicle, the so-called duty classification[3].

Battery electric vehicles (BEV) have enjoyed a much higher market penetration and development momentum in the light-duty sector, with at least three orders of magnitude more units in the market [4]. The high penetration of battery vehicles is partially explained by its lower total cost of ownership (TCO) when compared to fuel cells vehicles; it has been reported that for relative low travel ranges (< 400km), the total cost of ownership of fuel cell vehicles is much higher than for battery vehicles [3].

For fuel cell vehicles in the light-duty sector, the fuel cell stack and infrastructure utilization costs have a higher contribution than the hydrogen fuel in the TCO of these vehicles. Therefore, besides fuel hydrogen price, cost reductions in the elements mentioned above are crucial to achieving competitiveness in the

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[7] Hydrogen is largely employed in desulphurization process to remove sulphur in fossil fuels

market. In this sector, hydrogen prices between 4-7 €/Kg of hydrogen delivered to a refuelling station are expected to be acceptable to compete in the light mobility market [4, 17].

On the other hand, fuel cell vehicles in heavy-duty applications are expected to have higher chances of market penetration; the reasoning is that extended range, high daily mileage, and high flexibility are critical requirements for competitiveness in this sector [1]. However, In heavy-duty trucks, the hydrogen price has a much more substantial contribution to the final TCO[5]. It is reported that for ranges of at least 600 Km, hydrogen prices of around 7€/kg and fuel cell stack cost of 95 €/ Kg would be required to make heavy-duty fuel cell vehicles competitive with battery vehicles. For lower ranges, prices as low as 5 €/Kg would be required [3, 17].

Another application for a hydrogen fuel cell is in the forklift industry. Hydrogen forklifts are preferred over fossil-based, due to the limitations of combustion emissions in enclosed spaces. On the other hand, hydrogen forklifts are preferred over battery ones because they require lower charging times than batteries. Acceptable prices between 6-7 €/Kg of hydrogen delivered have been reported in the literature[3].

Fertilizer

Ammonia for fertilizer production is the second higher user of pure hydrogen demand today. Like the refinery case, the market is large, but the industry relies on low hydrogen prices. According to the IEA [3], an increase in demand due to population is expected in the short term. However, meagre electricity prices (<20 €/MWh) are required to make green hydrogen derived from electrolysis competitive in this market in the long term. If hydrogen prices after blue hydrogen are considered, electricity prices between 30 and 40 €/MWh are required to make green hydrogen competitive. These electricity prices translate into a price between 1 -2 €/Kg of hydrogen delivered to the end-user.

Iron & Steel Production

There are two main methods of primary steel production: Blast Furnace Basic Oxygen Furnace (BF BOF) and Direct Reduction of iron electric arc furnace (DRI EAF). BF BOF accounts for around 90% of the primary steel (steel produced from raw iron) production. In this process, hydrogen in mixed form is both generated and consumed. First, hydrogen is generated as a sub-product from coal gasification. Second, the produced hydrogen is re-utilized as a source of heat from combustion. Finally, the remaining hydrogen is sold to other chemical processes [3].

DRI EAF is an alternative route for primary steel production, accounting for around 7% of the global steel production [3]. In this process, a mixture of hydrogen and CO are used as a reduction agent. The hydrogen required for this process is typically produced in dedicated steam methane reforming (SMR) facilities. This production method is highly sensitive to energy and raw material input costs, accounting for up to 45% of steel production costs [3]. According to the IEA [3], electricity prices as low as 35 €/MWh would be required for green hydrogen to be competitive in the iron & steel industry (prices ~5 €/kg). Therefore, its application is also sensible to low hydrogen production prices. Another aspect to consider is that in the middle to long term, the primary steel industry might be hindered by over-capacities of the iron & steel sector and contributions from secondary steel production (steel produced from scrap iron) [3, 18].

High-Temperature Heat

Coal (65%), natural gas (20%), and oil (10%) are the main sources for high-temperature processes (e.g. 1600 ^{o}C for steel production) [3]. In this regard, when burned instead of electrochemically converted, hydrogen can be used as fuel to produce high-temperature heat. However, according to IEA [3], hydrogen for high-temperature heat is a significantly more expensive alternative than fossil fuels. In addition, it potentially requires several changes in terms of safety practices and current burning infrastructure.

Power Generation & Energy Storage

Hydrogen can serve as an energy storage medium, especially for long-term & large scale energy storage. This scenario is foreseen when large amounts of variable renewable energy need to be stored to maintain the balance of the energy system. During periods of large energy production, hydrogen can be produced and potentially be stored in salt caverns [19], depleted oil & gas fields and water aquifers [3]. However, this application depends on the geological availability of these sites.

Flexible power generation and load balance are other markets in which hydrogen could be used. The competitiveness of hydrogen concerning other alternatives is the function of the load factor of the generation units. In cases where low load factors of the units are expected, hydrogen could be more competitive than other low carbon alternatives such as biomass and natural gas with CC&S [3]. For the scenario in which hydrogen is produced only via Steam Methane Reforming (no carbon capture & storage considered), green hydrogen is estimated to be competitive at prices below 1.5€/Kg [3].

Table 1 summarizes the main market insights collected from the literature.

Table 1 Summary H_2 current market status & future opportunities [4, 3, 17, 20]

Application	Current Market [M Tonnes]	Future Perspective	Price* [€/kg]
Refinery	38	Slightly increase in demand after balancing out future reductions of oil demand and tighter fossil fuel pollution restrictions	1-2
Fertilizers	31	Increase in demand due to population growth	
Others (Electronics, glass making, metals, etc)	4.4	Mature industry. No significant demand growth expected	2-8
Forklifts	0.003	Significant market growth is estimated. However, market size is limited	6-7
Light Duty Mobility (Fuel Cell Vehicles)	<0.001**	Replacing the vehicle industry can create a large demand for renewable hydrogen (~100 M ton). However, fuel cell vehicles still need to reach competitiveness with battery vehicles	4-7
Heavy Duty Mobility (Trucks, Buses)	Demonstration & Niche Markets	There is a high potential for market penetration in long trip (> 600 km) heavy trucks. However, the market size is also limited, and complementary hydrogen applications still need to be found	5-7
Power Generation	Demonstration Projects	Potential applications in flexible power generation, backup power supply and energy storage	1-1.5

* Expected price for market penetration; ** Around 11200 vehicles currently in operations

3.2 Offshore Wind Energy

3.2.1 General Description

An offshore wind turbine is a device that transforms the kinetic energy contained in the wind to electricity in a marine environment. Wind turbines are grouped in wind farms to maximize the power extraction in a particular location at the minimum costs.

A measure of the net production cost of energy over a project life cycle is known as the Levelized Cost of Energy (LCOE). In particular, the LCOE of offshore wind projects has been progressively decreasing. Electricity prices < 100 €/MWh can already be found on projects such as Dunkirk in France and Borssele I/II in The Netherlands, with LCOE prices of 44 and 54.5 €/MWh, respectively[8] [2, 21].

In an offshore wind project, the LCOE is influenced by several elements: Project development costs (DEVEX), Capital costs for the wind turbines and electricity collection and offshore transmission systems (CAPEX), Installation, Operation & Maintenance[9] (OPEX) and decommissioning.

In the Netherlands[10], the offshore transmission system development and financing are currently done by the Transmission System Operator (TSO) (i.e. the costs are socialized). In contrast, the Offshore Wind Farm (OWF) operator pays grid connection and transportation fees.

Figure 8 depicts the relative cost contribution of different elements in an offshore wind project. As can be seen from the figure, the wind turbine assets (rotor, nacelle, etc.) constitutes around 30 % of the total cost. Therefore, projects are getting large to take advantage of the economy of scale, with increased wind turbines sizes [2]. Additionally, maintenance makes up to 19% of the total cost. Therefore, highly reliable system designs with reduced maintenance actions are favoured. Transmission costs, including cable (internal & export), substation and its respective installation, constitute around 15% of the total cost. Note that transmission cost increases significantly with distance from shore, and it is closely tied to the regional regulation for connection with the onshore grid [2, 22]. The aspects mentioned above could be determinants in the success or failure of an offshore wind project. Therefore, the system design of an integrated offshore wind-electrolysis system needs to consider these factors.

[8] For comparison in 2020 average onshore wind LCOE of ~33 €/MWh and PV solar LCOE 49 €/MWh are reported [91]

[9] OPEX also includes insurance fees

[10] Internationally, different structures are applied for grid development and financing.

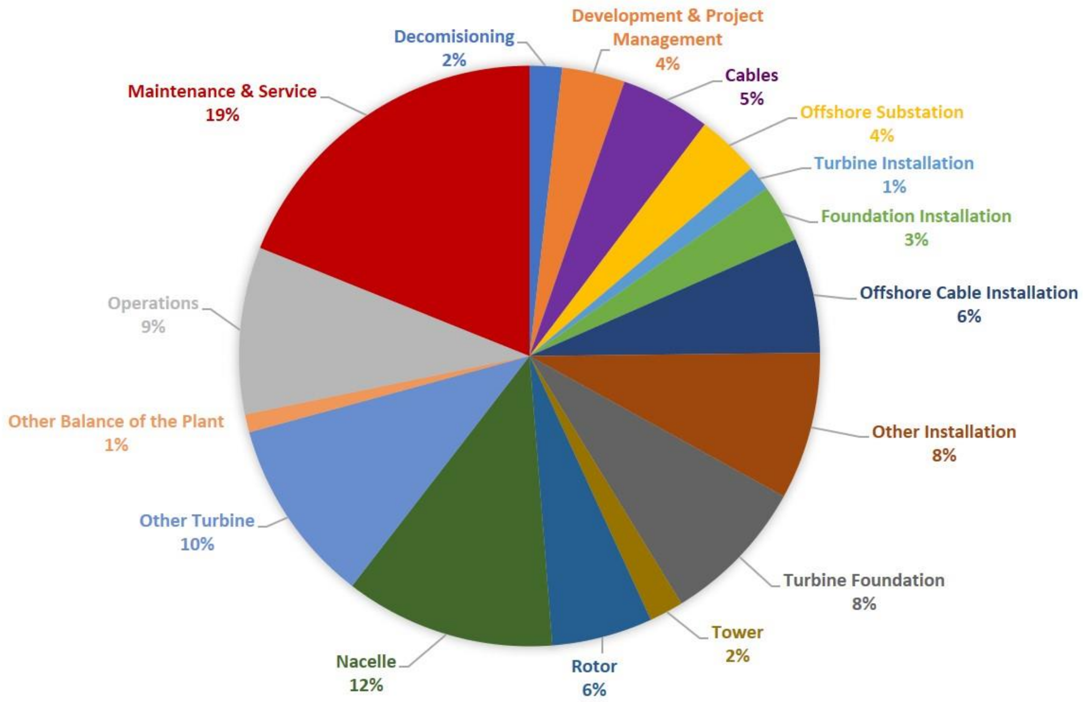


Figure 8 2019 Offshore Wind Cost Distribution. Data Adapted from [23]

In 2019, the average offshore wind turbine rating of new installations in Europe was around 8 MW, with wind farms under construction averaged at 621 MW [24]. However, rapid developments in rotor blade technology (e.g. weight and load reduction) and added benefits such as the potential of capturing more wind during periods of low wind speed (where electricity are usually higher) have led to a substantial increase in the rotor diameters and thus turbine size. For example, new offshore wind turbines with higher power ratings, between 12 -16 MW, have been announced and are currently under development [25, 26]

3.2.2 Offshore Wind Life Cycle

A typical offshore wind farm life cycle is composed of 4 main phases: development & project management, installation & commissioning, Operations & Maintenance, and finally, decommissioning [23].

Development & Project Management

This phase includes all the activities required before the start of the construction of the wind farm. The activities include (but are not limited) to perform surveys (environmental, hydrological, geological) and assessments (wind resource and MetOcean), Front-end Engineering and design studies (FEED) and management of the project to financial close.

Installation & Commissioning

This phase includes all the activities (land and sea) & logistics required for installation & commission of turbines and balance of the plant (e.g. offshore/onshore substations, inter-array/export cables and operations base)

Operations Maintenance & Service

This phase combines all the operation, maintenance, and service activities performed during the wind farm's operational life to ensure safe operation, maintain its physical integrity and optimise energy production.

Decommissioning

The operational lifecycle of current offshore wind farms is expected to be in the range of 20-30 years. Therefore, after the operational life of the windfarm is concluded, they are expected to be decommissioned and removed. However, due to the relatively recent deployment of offshore wind farms, there is still little practice & experience built about this process. Besides, this process's learning curve is slow because wind farms being decommissioned today are not comparable(e.g. size, number of turbines) to new wind farms being currently commissioned [27].

3.2.3 Offshore Wind Turbine Types

For offshore applications, full-rated converter, variable speed[11], either direct drive or geared, are currently the prevailing wind turbine technology in the market.

In direct-drive wind turbines, a direct mechanical connection is made between the rotor and the generator (direct drive), and the use of a gearbox is avoided. The absence of a gearbox gives the advantage of reducing moving parts that are prompt to failure, and therefore potentially lowering the associated maintenance costs [28]. However, as the generator operates at very low rotational speeds (e.g. ~25 rpm), large generator diameters (typically integrated into the wind turbine main bearing) are needed. For a long time, direct-drive turbines were only used onshore because producing and maintaining such massive generators and main bearings was not possible or regarded as risky. However, the potential reductions in maintenance costs have pushed this technology into the offshore market; for example, the 14 MW Haliade X wind turbine from General Electrics and the 14 MW SG14-222 from Siemens Gamesa are based on direct-drive design.

On the other hand, in a geared wind turbine, a gearbox is used to increase the rotational speed from the main rotor shaft to a high-speed shaft connected with the generator. As a result, smaller generator sizes can be obtained as the rotational speed is higher (e.g. ~500 rpm in a medium speed generator). However, the main issue is that the gearbox is one of the highest maintenance components of a wind turbine [29]. The reason is that the gears are moving parts subjected to severe cycle loading (due to variable wind loads) and therefore have an increased failure rate [30]. Nevertheless, geared wind turbine designs are still present in the market, such as the 16 MW MySE 16.0-242 from MingYang and the 15 MW V236 from Vestas Offshore.

3.2.4 Support Structures

Offshore wind turbines can, in general, be divided into two main parts: the rotor nacelle assembly and the structure which supports this assembly [31]. The support structures that can be used for offshore wind turbines are gravity-based, bottom-fixed monopiles and tubular metallic foundations. However, monopile

[11] Variable speed turbines are designed to operate over a wide range of rotor speeds.

structures are the most extended type of support structures used until now. In particular, in 2019, around 80% of the offshore wind turbines were supported in bottom fixed monopile structures [24]. On average, European offshore wind farms have been installed in water depths below 50 m. However, demonstration projects in waters depth above 100 m, such as the Hywind in Scotland, and the Windfloat Atlantic in Portugal, are currently under development [31, 32].

Besides, European wind farms have been installed in average distances to the shore of 59 km. As favourable near-shore locations become occupied, locations further offshore are now developed; for example, the Hornsea One wind farm in the UK has been installed at around 100 km to shore.

3.3 Water Electrolysis

3.3.1 General Description

An electrolyzer is an electrochemical device in which direct current (DC) electricity drives a chemical reaction. For water electrolysis, the aim is to split the water molecule to extract mainly the hydrogen (H_2) component (see Equation (1)). This splitting reaction ideally requires at least 9 L of water & 33.3 kWh of energy per kg of hydrogen produced. However, in practical higher water (11 L) and energy (55-63 Kwh) requirements per kg of hydrogen produced can be found. In addition, around 8 Kg of oxygen (O_2) per kg of H_2 are obtained from the conventional reaction[12] as a by-product.

$$H_2O + e^- \rightarrow \frac{1}{2}O_2 + H_2 \; \left(HHV: 39\frac{kWg}{kg}\right) \qquad (1)$$

The electrolyser consists of at least an anode, a cathode, and an electrolyte medium in its simplest form. In general, water electrolysis is classified by the operating temperature and the type of electrolyte used. For example, Figure 9 summarizes the different types of water electrolysis for hydrogen production

[12] Research is being conducted in paired electrolysis, in this case hydrogen peroxide is obtained as by-product

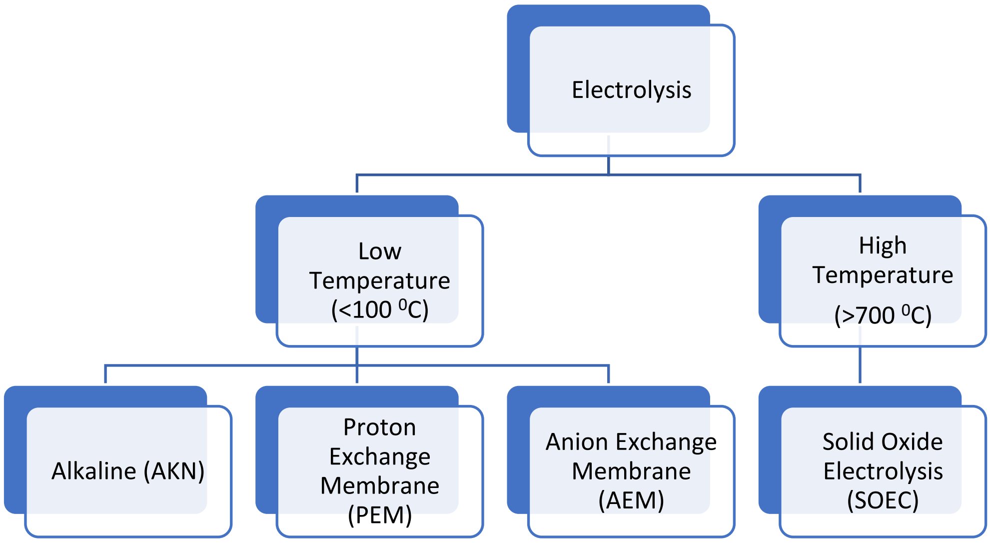


Figure 9 Electrolysis Technologies Types

In Figure 9, low-temperature electrolysis refers to technologies that operate at temperatures below 100 ^oC, from which alkaline(AKN), Proton Exchange Membrane (PEM) and Anion Exchange Membrane (AEM) electrolysis can be distinguished. On the other hand, high-temperature electrolysis refers mostly to the Solid Oxide electrolysis (SOEC) technology, which operates in temperatures between 700-1000 ^oC [33]. A general description of these technologies is given as follows:

Alkaline electrolysis: This technology operates in an alkaline electrolytic media, for which a dissolved electrolyte, such as KOH (potassium hydroxide), is used. The presence of alkaline media allows cheap materials such as Ni/Fe to catalyse the reaction. In the market, stack modules from 2 to 4 MW can be currently found. This technology operates at temperatures between 60 - 90 ^oC, with typical output pressures in the range of 1-30 bar [34].

PEM Electrolysis: This technology is characterized by an acidic solid electrolyte that enables a smaller footprint compared to alkaline electrolysis. Although less mature than alkaline electrolysis, this technology has reached MW scale, with stack modules in the range of 1 - 3 MW [35, 36, 37], although stacks sizes of up to 5 MW are being developed [13]. The main challenges of this technology rely on its scalability for cost reduction, the relatively lower stack lifetime, and the use of rare metals (or noble metals), which are needed to resist the harsh conditions of the acidic environment.

SOEC Electrolysis: This technology is characterized by using solid ceramic-based electrolytes and steam water for operation. This technology is in the demonstration phase, with pilot projects at scales of up 2 MW launched [38]. The main advantage of this technology, providing that a high-temperature source is available, is the potentially higher electrical efficiency than other electrolysis technologies. This system operates at temperatures above 700 ^oC, and pressures in the range of 1-15 bar [34].

AEM Electrolysis: This technology uses a solid alkaline electrolyte for operation. It potentially combines the high flexibility and compactness of PEM electrolysis but with the economic advantages of operating in an alkaline medium (no costly noble metals required). This technology is still under development, as technical problems such as the potential degradation of the catalyst resulting from a variable electrical input (similar to AKN electrolysis) and the membrane's degradation still needs to be addressed [39, 40]. Although this technology is still in the early phases of development to be considered in this project, it is essential to monitor future developments in the field, as it can positively impact the project in terms of cost reduction and environmental impact.

Table 2 summarizes the main technical characteristics of the alkaline, PEM and SOEC electrolysis technologies. Note that due to the relatively low Technology readiness of AEM electrolysis, this technology is not included in the table.

Table 2 Water Electrolysis Technology's Characteristics [1, 3, 34, 13]

Parameter	**Technology**		
	Alkaline	**PEM**	**SOEC**
Energy Requirements [Kwh/Kg_{H2}]	51	58	41
Nominal System Efficiency (LHV) [%]*	63-70	56-60	74-81
Current Density [A/cm^2]	0.2-0.6	1-2.5	0.3-1.0
Cold Start-up Time	1-2h	5-10 min	Hours
Warm Start-up Time	1-5 min	< 10 s	~15 min
Load Range [% nominal Load]	20-10	~10-200	-100/+100
Stack Lifetime [h]	80000	40000-80000	8000-20000
Max. Nominal power Stack [MW]	2-4	2-3(5**)	<0.01
CAPEX [€/MW]* **	500-1400	1100-1800	2800-5600
Stack Replacement [€/MW]	340	420	N.A
Operating Temperature [C]	60-90	50-80	700-1000
Typical Output Pressure	1-30	30-50	1-15
Plant Footprint [m^2/MW_e]	~26-95	~19$^+$-48	--
System Lifetime [Years]	20	20	--

*SOEC does not include the required energy to generate steam; **5 MW stacks in development (ITM POWER);*** Including power electronics, gas conditioning and balance of plant; $^+$ Containerized electrolyzer type only

3.3.2 Offshore Electrolysis Applicability

As an electrolyser is a fundamental piece in this design project, an analysis of the different electrolysis technologies characteristics for application offshore is performed. A summary of the analysis can be found in Table 3, which is further described afterwards.

Table 3 Comparison of the three main types of water electrolysis

Technology	Advantages	Challenges/Drawbacks
Proton Exchange Membrane Electrolysis (PEM)	• Smallest footprint • Highest current densities • Higher load range than AKN • Fastest response time/dynamics • Deliver pressurized H_2 (~30 bar)	• Precious metal catalyst required (economic & environmental impact) • Lower lifespan than AKN • A harsh environment requires more expensive component materials
Alkaline Electrolysis (AKN)	• Lowest CAPEX • Highest lifespan • Use of relatively abundant resources	• Much slower response time/dynamics than PEM • Lower current densities than PEM • Requires periodic electrolyte renewal • Higher footprint than PEM • Less turndown ratio than PEM • Potential electrode degradation with variant power input
Solid-Oxide Electrolysis Cell (SOEC)	• Highest electrical efficiency • Non-noble catalyst used	• A source of heat at high temperature (> 500 C) is required • Limited flexibility/dynamics • Potential induced thermal fatigue • Lowest TRL
** TRL: Technology Readiness Level		

Alkaline Electrolysis

Compared to other electrolysis technologies, Alkaline electrolysis has the relative advantage of lower investment costs and the higher life span of the device in continuous operation. However, the fluctuating nature of variable renewable energy (VRE) sources such as offshore wind can lower the expected lifetime, as the electrodes may degrade during intermittent operation [41, 42].

Regarding its integration with VRE, a well-known limiting factor is the slow dynamics of this system (including long start-up times). The slow dynamics of this technology, especially the relatively long cold/warm start-up, makes it challenging to integrate with the fluctuating nature of offshore wind turbines. Furthermore, due to the potential generation of flammable mixtures, alkaline electrolysers cannot operate at load ranges below 20 % of rated power [3], which are likely in wind turbine operation.

In terms of application for an offshore environment, alkaline electrolysis might be hindered by the periodic need for electrolyte renewal. The reason is the high logistic cost of performing maintenance operations offshore, which can be observed in the Levelized cost contribution of O&M operations as discussed in section 3.2.

Alkaline electrolysis is also characterized by having a relatively large footprint. The reason derives from using a liquid electrolyte that occupies more space than a solid electrolyte (Such as PEM Electrolyzers) and the relatively low current densities achieved [43]. Large footprints are a negative aspect in an offshore environment where expensive installation and support structures manufacturing costs, limited available space govern.

PEM Electrolysis

PEM electrolysis has important characteristics regarding its integration with Variable Renewable Energy (VRE). The main characteristics are the broader operating range (10-200%)[13] than alkaline technologies (20-100%), the quick response time, and the lower footprint than other electrolysis technologies. The first two characteristics are advantageous as the flexibility offered by PEM electrolysis could be used to accommodate the offshore wind production profile. As mentioned before, the last characteristic is fundamental in an offshore environment, where the cost of a support structure can be prohibitive.

In addition, PEM electrolysis can produced hydrogen under pressurized conditions (>30 bar). Pressurized hydrogen is advantageous as it reduces downstream compression & transport costs.

Providing that the power electronics are designed accordingly, the possibility to operate this technology in overload conditions (up to 200% of the nominal rated capacity) for a limited period (10 to 30 min) has also been reported [1, 34]. This characteristic opens the possibility of exploring design/operation strategies, such as minimizing the electrolyzer size and allowing limited overload operation. Also, operation strategies that regulate the amount of power sent electrolyzers to maximize efficiency can be studied at a wind farm level.

This technology's main challenges/drawbacks relate to the higher cost and relatively lower lifespan of the stack compared to alkaline technologies. However, several efforts, such as the GIGASTACK project [13] in UK and the Faraday lab [44] in The Netherlands, are aiming to bring down the cost and improve the performance of these technologies.

Solid-Oxide Electrolysis Cell (SOEC)

At the moment, solid oxide electrolysis presents several limitations for its integration with wind energy in an offshore environment. First, obtaining the benefits of the highest electrical efficiency requires a high-temperature source for operation. Unfortunately, high temperatures sources are unlikely found in an offshore environment (at least combined with an offshore Oil & gas facility). In addition, compared to PEM and alkaline electrolysis, it has the slowest/response time, lowest lifespan, and potentially the highest footprint [34]. All of these parameters affect its viability for offshore operation negatively.

The previous analyses show that PEM electrolysis offers superior characteristics for integration with the offshore wind turbine. This technology has the highest dynamic response, which is required to follow the fluctuating power production of the turbine (due to wind fluctuations). Second, it has the smallest footprint, which facilitates the physical integration with the turbine structure. Third, it has a higher operating range than alkaline, which is needed because low wind speed periods with resulting low wind power production

[13] Providing that BOP and Power electronics are designed to operate at higher ranges too.

are expected. Finally, it is a technology with proven pressurized operation, which can facilitate hydrogen transfer to shore and reduce the energy and footprint demand of downstream equipment.

3.3.3 Dynamic Operation

When the electrolyzer is coupled to a fluctuation energy source such as a wind turbine[14], it will operate in a wide load range typically defined as a percentage from the nominal rating. As no standard has been yet established, the definition of nominal rating is a function of the manufacture. However, from manufactures datasheets, it is possible to estimate that the nominal rating will be expected when the electrolyser stack operates at efficiencies between 70 to 80%, based on the low heating value (LHV).

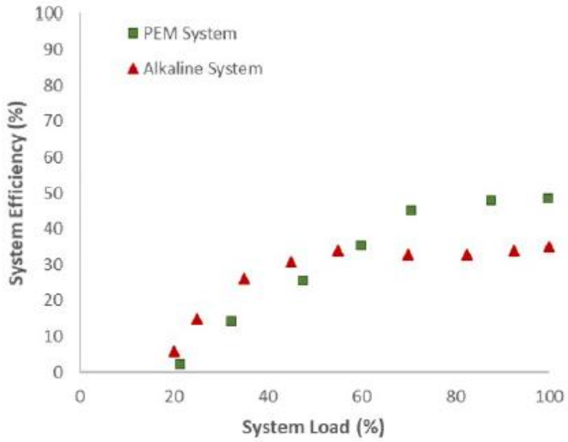
The limits of the operating range indicate the ability of an electrolyzer to operate under dynamic conditions. The upper limit is conditioned by the electrolyser materials' potential degradation, which occurs at high voltages. On the other hand, the lower limit is conditioned by the gas purity in the cell's electrodes. Low operating loads lead to contamination of the produced gases with each other. This gas mixing is of particular concern in the anode side, where the oxygen is produced as built-up of hydrogen can generate spontaneous combustion [43]. As shutdown periods derived from the low availability of the renewable energy source can occur, the system's response time is of particular importance. Due to the relative delay that a cold start-up may imply, a common practice is to operate the electrolyzer in idle mode until the energy source is available again [45]. From that point, the electrolyzer power is ramped up to the corresponding level. The idle mode is maintained by providing a minimum external backup power. Note that all the system components need to be designed to guarantee the required time response to allow high dynamic operation. Time delays can occur in complementary systems such as valves, pumps or even signals from the temperature sensors [45].

A practical feature of PEM electrolyzers is that they can be operated (for a limited amount of time) under overload conditions (up to 200% [1, 34]). However, overload operation could potentially lower the lifetime of the cell components. Therefore, an optimum between lifespan and overload has to be found [43].

At loads below rated power, the electrolyzer stack becomes more efficient. However, at the same time, the balance of plant and power electronics become less efficient. Therefore, the system's total efficiency would be a balance between the design and operating strategy of the system. For example, Figure 10 (left) shows an alkaline and PEM electrolysis pilot project in which systems efficiencies as low as 2% and 6 % occurred at power inputs of around 20 % the rating [45]. These low efficiencies mainly were attributed to losses in the balance of the plant and power electronics.

On the other hand, Figure 10 (right) depicts an electrolyzer system that uses a smart operating strategy at low operating loads. The figure shows that the system's efficiency improves at a lower load, reaching a peak at around 20% of the rated systems load. Below 20% load, the attained efficiency starts decaying less dramatically than in the first case (Figure 10 (left)).

[14] Note that the wind fluctuations are highly dependent of the site location, although in general more stable winds are expected in offshore the sea.



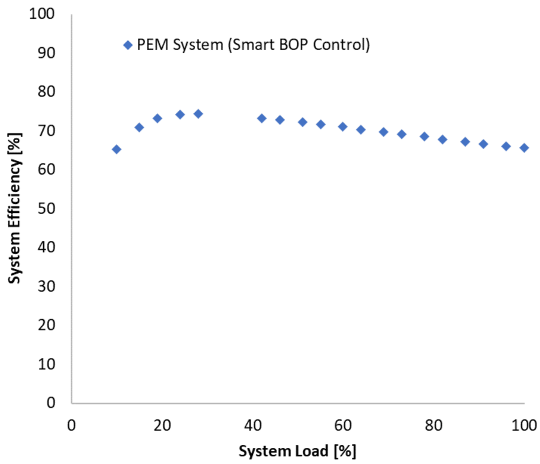


Figure 10 (Left) PEM & AKN System Efficiencies (left) no BOP control (right) smart BOP control. Adapted from (left) NREL [46]& (Right) ITM [35]

3.4 Hydrogen Safety Considerations

Hydrogen, as any fuel, has associated dangers that need to be considered early in the design to ensure the integrity and safe operation of the system.

Hydrogen is characterised for having a high flame velocity (346 cm/s), a broad ignition range (4-77%), and a low required ignition energy (0.02 MJ). The combination of these aspects makes the hydrogen compound highly flammable. On the other hand, hydrogen is also characterised for having a small molecule size. The small molecule's size makes hydrogen prompt for leaking. The leakage can occur at several system parts, such as compressing fitting and valves. Therefore, proper tightening and continuous leak detention are used to prevent and correct potential leaking [45].

In open spaces, the high buoyancy and diffusion coefficient helps hydrogen rapidly dissipate when released in case of a leak [47]. However, in enclosed environments, system concentration built-ups can occur that in turn generate hazardous gas mixtures. In fact, under standard conditions, volume concentrations above 4% of hydrogen in oxygen are spontaneously combustible. This combustibility limit results in volume concentration limits below 2 % in practical applications for safety reasons.

Besides concentration built-up due to leakage, low load operating ranges (likely occurring when with variable energy sources) can generate concentration builds-up in the electrolyzers. In this case, built-up due to the hydrogen produced in the cathode side can permeate (known as crossover) the membrane towards the anode side, in which the oxygen is produced. The problem at low load operating is that oxygen production decreases, whereas the crossover rate independent of the operating load (but instead of the pressure difference in the stack) remains the same. In practice, the stack needs to be supplied with energy for minimum oxygen production to avoid H_2 concentrations build-up. However, this additional supply of energy lowers the efficiency of the system. Therefore, an optimum can be found between stand-by operation and fully shut-down the stack [43].

Several elements such as combustible gas detectors, UV/IR fire detectors, and ventilation are typically part of the safety system. These systems require an uninterruptible power supply for safe operation [48]. Note that some of these safety systems, such as the gas detectors, require periodic calibration [45].

In addition, due to the weather conditions at which the electrolyzer may be exposed, the electrolyzer response to offshore motion needs to be validated [48]. There is a lack of statistical reliability metrics (such as mean time between failure, mean time to failure etc.) for electrolysis systems in an offshore environment. These metrics need to be collected to assess the systems reliability and maintainability, identify problems within the system, and enable comparisons with other similar equipment [45].

Finally, during an engineering project, It is necessary to ensure that the designed system complies with existing applicable regulations & and codes, as well as take into consideration relevant standards & procedures. For the case of Europe, the Fuel Cell and Hydrogen Joint Undertaking (FCH2JU) has prepared a "Safety Planning for Hydrogen and Fuel Cell Projects" report, which includes a comprehensive database of the elements discussed above [59]. Note that specific regulations and standards are not yet available for electrolysers in an offshore environment. However, directives for offshore operation such as the Directive 2013/30/EU[60][61], combined with current standard/guidelines for onshore electrolyzer, can be the first step for offshore application. As a reference, some of the potential applicable standards/guidelines are listed below:

Table 4 Potential Applicable Standards & Guidelines

Application	Standard/ Guideline	Standard/Guideline Name	Year
Hydrogen Purity	ISO 14687	Hydrogen Fuel Quality: Product Specification	2019
	NEN-EN 17124	Hydrogen Fuel- Product specification and quality assurance PEM fuel cell applications for road vehicles	2018
Electrolyzer Requirements	ISO 22734	Hydrogen Generators using water electrolysis industrial, commercial and residential applications	2019
Safety Hydrogen	ISO/TR 15916	Basic considerations for the safety of hydrogen systems	2015
Hydrogen Detection	ISO 26142	Hydrogen Detection Apparatus	2010
Offshore Safety	D 2013/30/EU	Safety on offshore oil & gas operations	2013
ATEX Directive	D 99/92/EC	Minimum requirement for improving safety and health protection of workers potentially at risk from explosive atmospheres	1999
	2014/34/EU	Protective systems intended for use in potentially explosive atmospheres	2014
Hydrogen Safety Guide	NREL/TP 5400-60948	Hydrogen Technology Safety Guide	2015

3.5 Offshore Wind-Electrolysis Integration

The concept of offshore wind electrolysis integration is relatively new, and therefore, little literature is available in this regard. However, this concept is gaining increased attention in the industry, with recent project initiatives and assessments unveiling the potential benefits of this integration [11, 48, 49, 50, 12, 7].

In general, two types of concepts have been proposed in the industry: decentralized and centralized offshore electrolysis. The first concept refers to the physical integration of the electrolyzer in the wind turbine. In this way, decentralized production in each turbine of a wind farm is performed. The second relates to a centralized hydrogen production, in which electricity is delivered to a dedicated offshore platform where the electrolysis process is performed. A further description of project initiatives regarding these two concepts is given below.

Integration in the support structure

For this concept, three initiatives namely, The Dolphyn, ITM-ORSTED and the Deep Purple, have been recently announced.

The Dolphyn concept proposes integrating a PEM electrolysis system and a 10 MW wind turbine, on a moored floating sub-structure, in a deepwater location. The concept was selected after performing a techno-economical study that compared the cost of production in 3 cases: decentralized in floating wind turbines, centralized in an offshore platform, and centralized in an onshore facility. The concept evaluation results favoured the integrated system's hydrogen production in the semi-submersible support structure. A comprehensive description of the design choices and selection process can be found in [48].

The ITM-ORSTED concept proposes utilising a wind turbine that directly powers an electrolyzer in a marine environment. The electrolyzer is placed inside or in the vicinity of the turbine tower. As a result, the concept would benefit from lower conversion steps, the use of the cooling capacity of the sea to remove the excess heat from the electrolysis process, and the transport of energy via pipeline [50].

Similar to the initiatives above, TechnipFMC is assessing the technical feasibility of an electrolysis system physically integrated into the tower of an offshore turbine. In their concept, the tower's base is vertically divided into multiple sections, in which a series of electrolyzer and water treatment plants are placed. The concept is part of the Deep Purple™ initiative that aims to stabilize offshore energy production by providing large scale sub-sea storage in ports [49].

Integration in a centralized platform

For this concept, two initiatives were identified: The PosHydon and the Tractebel platform projects

In the PosHydon initiative, a 1 MW electrolyzer would be placed in an existing fully electrified offshore platform. The pilot project aims to gain experience in water electrolysis in offshore environments (including installation and operation) and serve as a testing centre for new power to gas technologies [11].

On the other hand, Tractecbel intends to develop a large scale green hydrogen production plant located on an offshore platform. The expected platform plant is intended to cope with wind farms delivering up to 400 MW of power rating [12].

3.6 Summary of findings

Market: Hydrogen as a feed-stock is an established market, which has several uses in the industry, such as refining processes and fertilizing production. However, these markets are dominated by grey hydrogen in which production prices of around 2 €/kg are found. For green hydrogen to be competitive in the feed-stock market, electricity prices between 20-30 €/Mwh are required. In addition, further reductions of the electrolyzer CAPEX cost and high operating hours are also needed.

Green Hydrogen could potentially be utilised in several markets, such as power balance, backup & storage, mobility, and steel production. However, in the middle term, the emerging heavy-duty mobility market with prices between 5-7 €/kg appears to be the most promising market for green hydrogen production.

Several aspects such as support structure, installation, operation, and maintenance must be considered during the design of the intended system. They are critical points to minimize the Levelized cost of electricity (and therefore, the Levelized cost of hydrogen). Current trends of offshore wind turbines favour larger wind turbines with incoming power rating capacities in the range of 12 – 16 MW.

Electrolysis Choice: PEM electrolysis is found to be the most suitable technology from the technical point of view to be used in an offshore environment. Its main advantages are footprint, dynamics of operation, operating range, low maintenance requirements, high output pressure, and relatively high current densities. On the other hand, the main disadvantage of this technology is the high CAPEX cost resulting from the usage of precious metals and the early stage of manufacturing development.

Dynamics Operation: Sizing and the operation strategy are essential aspects to consider in the design. For example, although electrolysis is more efficient at low operating loads, the plant and power electronics balance tend to be less efficient. Therefore optimal operation strategies need to be found.

Safety: there are no standards or codes for designing an offshore wind-electrolysis system. However, several directives, standards and codes available for onshore electrolysis and operation in an offshore environment could be used as the first step for the integration.

Regarding the integration of wind and hydrogen, the operating ranges of the system are of particular importance. The upper range is limited by the degradation of the electrolysis cell, whereas the purity of the gas limits the lower limits. The lower operating limit is critical as hydrogen crossover mixes with oxygen and potentially reaching the hydrogen's flammability limit (~4 % v/v). Besides, concentration built up in closed space shall also be considered and avoided to ensure the system's safety.

Offshore Wind Electrolysis: Regarding the offshore wind-electrolysis system, some initiatives are already present in the industry. These initiatives have two approaches to integrating the electrolyzer in the support structure of the turbine and centralized hydrogen production in an offshore platform. However, these initiatives are still under development, and the best alternative is still yet to be defined.

4 Preliminary System Design

In this section, a preliminary system design is generated based on a top-down systems engineering approach. First, a requirements analysis is performed to translate the needs and expectations into a set of system requirements. Next, primary functions to fulfil those requirements are identified. Finally, technology selection is performed to allocate technologies to the required functions and generate logical architectures.

4.1 Requirements Analysis

This analysis intends to define what is expected from the system in a clear set of requirements. The inputs for this analysis were results from previous desk studies [7], the literature review (see section 3), and discussions with the project's stakeholders.

4.1.1 Design Basis & Assumptions

Below a set of inputs, constraints and assumptions used as a basis for the design are described:

• **Operational Context:** The system is designed for operation under environmental conditions present at the Dutch Economic Zone of the North Sea. Therefore, a typical wind profile in the North Sea will be used as a reference. This decision implies that the system operates in a saline and harsh environment in which stricter reliability and safety requirements are expected. Besides, as the environment is remote, remote operation is required.

• **Dedicated Hydrogen Production:** The system is assumed to operate in an offshore scenario decoupled from the electrical grid. The system is conceived for the dedicated production of hydrogen offshore.

• **Hydrogen Production Technology:** From previous desk studies [7], electrolysis was established as the preferred technology for hydrogen production. In addition, from the literature review findings and after discussion with TNO experts, PEM Electrolysis is explicitly selected as technology to integrate with the wind turbine. As discussed in section 3.3.2, this decision is based on advantageous technical characteristics of PEM electrolysis over other technologies (such alkaline) in terms of faster dynamics (needed to handle power fluctuations from the turbine), higher current densities with lower space footprint (needed to facilitate the physical integration with the wind turbine), higher turndown capacity (needed to handle intermittency of power production), and the possibility of producing pressurized hydrogen (helpful to potentially transfer the produced hydrogen to a centralized collection point).

• **System Life Cycle:** A “typical” offshore wind farm life cycle (See section 3.2.2) with a life expectancy of 20 years is set as a reference for the design. Therefore, aspects such as installation, maintenance, and accessibility are considered during the design. The design considers current and expected technology in a time-frame up to 2025.

• **Reference Turbine:** The IEA 15 MW reference wind turbine [51] from the National Renewable Energy Laboratory (NREL) is selected as a baseline for the concept exploration. The use of a reference turbine was needed because detailed information of offshore wind turbines and their performance is not publicly available. Besides, the selected turbine’s capacity (15 MW) is in alignment with the growth trends of the offshore wind industry in which wind turbines power rating between 12-16 MW [25, 26, 52] (currently under development) are expected to be commercial in the incoming years.

• **Reference Wind Farm Size:** A reference 700 MW wind farm size is selected as a baseline for the concept exploration. The need of defining a wind farm size is because the integrated electrolyzer-turbine will certainly be constructed, installed, operated, and maintained within a wind farm context. In addition, the potential benefits of having centralized parts of the system (such as compression) can be analysed. This wind farm power size is in line with incoming wind farm developments in the industry [53].

4.1.2 Market Application Scenario

In section 3.1, a review of the hydrogen's current status & market opportunities was conducted. This analysis concluded that the market niche of high purity hydrogen has the highest potential for integration in the near term and thus is targeted in the design. In particular, the heavy-duty mobility sector is expected to have the highest market potential in the coming years. Although this market niche is anticipated to develop in the coming decade, hydrogen prices at around 5-7 €/Kg[15] are needed today for hydrogen to be competitive in this sector. Therefore, this price range is used as a referent for the design.

Note that high purity hydrogen has higher demand in bulk industries such as fertilizers production & refineries with current end-user prices <3 €/Kg. Therefore, future applications supported by technological development and policies could include these sectors.

4.1.3 System-Level Requirements

Once the design basis and application market are established, a discussion with the stakeholders is performed to define the system needs. These needs are the stated stakeholder's expectations of the design, and therefore are the foundation for further design decisions. Following the systems engineering approach, the needs were translated into a series of system-level requirements. However, when a need cannot clearly be established as a requirement because it is subjective, ambiguous or over-stringent, it is stated as a system goal. The resulting system requirements and goals are enlisted in Table 5.

[15] This value corresponds to the estimated end-user price, equivalent to the prices for fossil-based vehicles.

Table 5 Requirements & Goals at the System Level

Tag	Description
System Requirements	
SR1	The system shall produce hydrogen from offshore wind energy
SR2	The system shall operate decoupled from the electrical grid
SR3	The system shall deliver the produced hydrogen to an offshore collection point
SR4	The system shall be designed for a "typical"* North Sea offshore environment conditions
SR5	The system shall operate unmanned
SR6	The system shall use PEM water electrolysis to produce hydrogen**
SR7	The system shall be designed for an operational lifetime of at least 20 years
SR8	The Levelized Cost of Hydrogen (LCOH) of the integrated system should be below 5 €/kg
System Goals	
SG1	The Levelized Cost of Hydrogen (LCOH) of the integrated system should be competitive with current fossil base methods of hydrogen production (< 2€/kg)
SG2	The system should be able to be safely operated & maintained

* Later in the design, the environment conditions at IJmuiden Ver. were set as a reference for this requirement;
Design constraint resulting from stakeholder's discussions & preliminary studies (see **[7])

4.2 System Functional Analysis

The objective of the functional analysis is to identify the minimal functions that the system needs to perform to fulfil the previously identified requirements and to have an overview of the interactions that the system has with its environment. Note that except for water electrolysis and renewable energies, the functional analysis is kept at a high level to avoid selecting a specific technology too early in the design.

Figure 11 shows an overview of the identified system's highest-level functions, consisting of: produce energy from offshore wind, produce water for electrolysis, produce hydrogen from electrolysis, and transfer the produced hydrogen to a collection point. Besides these essential functions, the system also needs to provide some structural support (to contain and fix the equipment offshore), enable remote control (to operate unmanned), enable maintenance services and provide a minimum of backup services (to operate off-grid safely). In addition, cooling is included anticipating the need of handling the large waste heat generated from the electrolysis process.

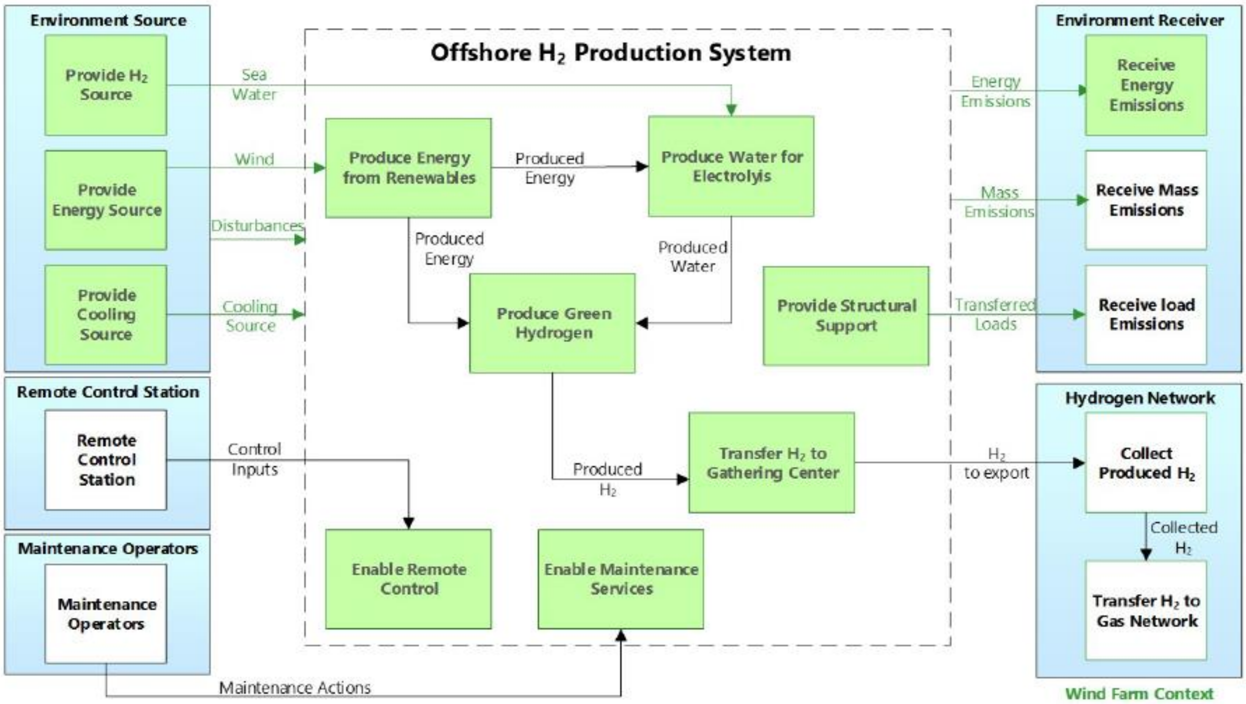


Figure 11 System Functional Decomposition

Figure 11 also depicts the different interfaces of the system with external entities. The primary identified interfaces are described below:

Environment: the local environment interacts with the system differently. These interactions are:

- **Source:** As stated in the design assumptions, limited or non-access to pre-treated sources (e.g. tap water, grid electricity) is available. Therefore, direct intake of energy (electricity) and hydrogen source (water) from the environment is expected. Besides, it is also expected to use the environment as a cooling source (e.g. seawater cooling or air cooling). The interfaces of the system with the environment are the seawater intake point for water production and the turbine rotor for energy production. The interfaces for cooling are the seawater intake point (e.g. for electrolysis cooling defined in section 4.3.3) and the air intake point (e.g. for generator, converter & nacelle cooling[16]) when water and air are used as cooling media, respectively.

- **Disturber:** Typical perturbations from the environment includes wind, wave & current loads, seasonal environmental changes (e.g. temperature), corrosion, among others. Several impacts can result from disturbances, such as difficult/no access to the turbine for long periods, potential communications losses, and intermittent or partial operation of the central collection point. Interfaces here are the whole structure exposed to the environment and its disturbances.

- **Receiver:** The environment receives emissions such as mass & heat exchanges (due to the losses in the system), sub-product discharges/leakage, among others from the system. Besides, typically from wind turbines, the system transfers the loads (from wind waves, currents, etc.) back to the

[16] As a reference the air-to-air heat exchanger are used for the 12 MW Haliade-X cooling system [134]

environment to ensure the system's integrity. The interfaces here are the rejection points for mass exchange and the surface areas exposed to the environment for heat exchange.

Hydrogen Gas Network: The produced hydrogen is transferred and collected at a collection point. After collection, the hydrogen needs to be transmitted to the end-user. Although outside the design limits, it is evident that the system will eventually interact with gas transmission network operators. The interface would be the transmission pipeline from the collection point to the connection point in the gas transmission network. A critical parameter, in this case, is the operating pressure of the gas transmission network; as a reference for the design, current operating pressures for onshore gas pipelines are in the range of 70-100 bar [54, 9].

Maintenance Operators: The system shall enable maintenance operators to service the turbine. Therefore, safe access to the turbine, enough space to perform repairs, and a safe environment to perform the works are paramount to the design. In addition, interactions with service vessels to perform major (e.g. replacement of big parts) or minor (e.g. scheduled visits) activities are present in this context.

Remote Control Station: As the unmanned operation is set as part of the requirements. The system interacts with a remote control station. The interface in traditional offshore wind farms is the fibre-optic element in the submarine cable that allows data transfer and monitoring. Although communications are out of the scope of the design. The concept of a fibre optic data cable along the pipeline already exist [55] and could be applied.

• **Wind Farm Context:** Although the initial concept envisages a single turbine-electrolyzer integration. It is worth noting that the wind turbine will be operating as part of an offshore wind farm. Therefore, potential synergies and interactions within the wind farm (centralized compression, maintenance activities, logistics) need to be considered during the design process.

Zoom-in Functional Decomposition

Further decomposition of the functions shown in Figure 11 was performed to define lower-level functions and interface requirements. For illustrative purposes, Figure 12 depicts the decomposed function "produce energy from offshore wind", for which further description is given below.

In this Figure 12, wind energy provided by the environment is captured & transformed into mechanical energy. To maximize the energy capture, the system needs to be positioned in height and orientated towards the wind (adjusted based on the measured wind characteristics). Next, the produced mechanical energy needs to be transformed into electricity, which is then conditioned before it can be transferred for later utilisation.

Besides electricity production, additional functions are required to maintain the integrity of the wind turbine. In some events, such as reached rated power production and extreme weather, the capture of energy needs to be limited to protect the system.

In addition, due to the nature of offshore wind energy production, the system will be subjected to continuous mechanical loads coming from the wind, waves, and currents. These loads need to be transferred back into the environment by providing structural support to the system. Also, as energy is being produced, the system is likely to generate heat losses. Again, these losses need to be removed and transferred back into the environment. Finally, note that the system also disturbs the environment by heat rejection and the resulting disturbed wind after energy capture.

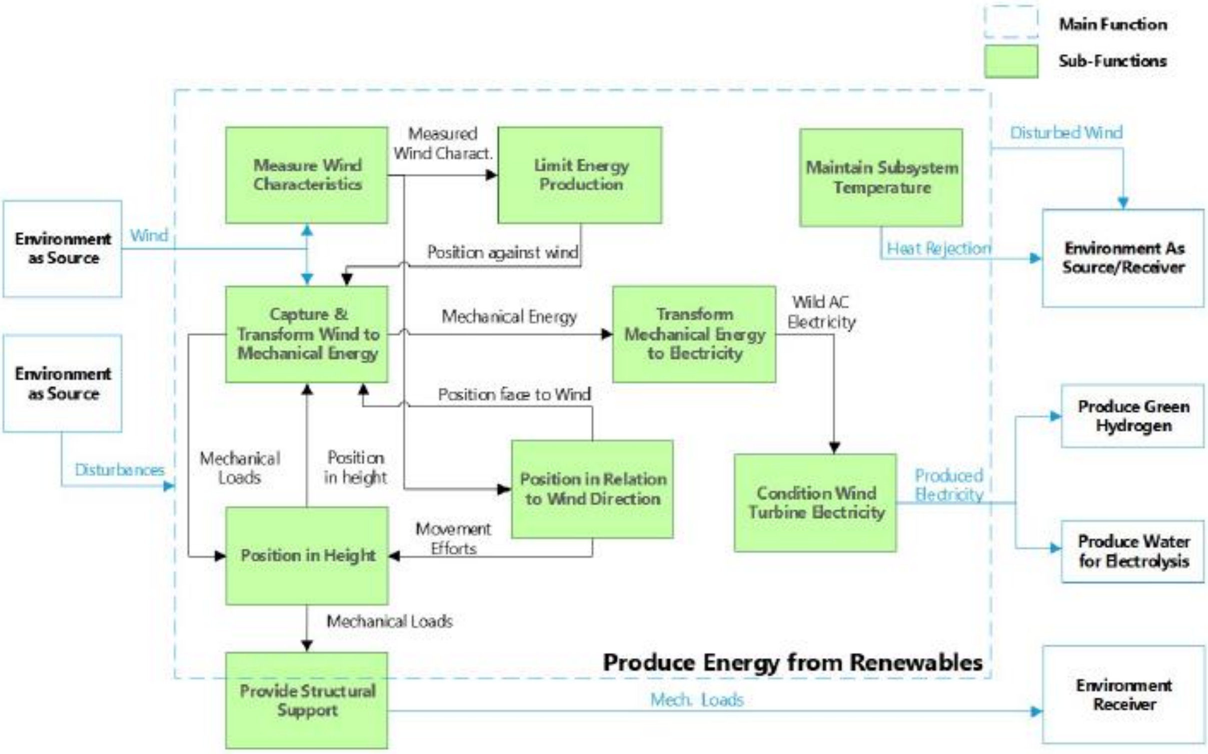


Figure 12 Produce Energy Functional Decomposition

A similar decomposition is performed to the system main functions "produce water for electrolysis" and "produce hydrogen" as they are the main interest in this design stage. These decompositions can be found in Appendix B. The description of the mentioned decomposed functions is omitted here as it is used in the following sections to facilitate the description of the relevant analysed system.

4.3 Logical Architecture

This section aims to allocate the identified system functions (and lower-level functions) to a set of suitable technologies. When multiple technologies could potentially be allocated to a function, technology selection is performed. This allocation is part of an iterative process in which discussion with Subject Matter Experts (SME) is used as input for the design refining and validation.

As a starting point for technology allocation, a rough estimation of the water and hydrogen flow rates when the 15 MW reference wind turbine operates at rated power are calculated (assuming 1:1 turbine generator-electrolyzer rated capacity). Besides, as some process technologies benefit with scale (and might thus be preferred to be centralized), a similar estimation is performed for the wind farm context.

The resulting flow rates are summarized in Table 6 below.

*Table 6 Rough Estimation of Water and Hydrogen Flow Rates at Single Wind Turbine and Wind Farm Scale***

Parameter	Wind Turbine (15 MW)	Wind Farm (700 MW)
Water consumption [m^3/h]	~3	~154
Hydrogen produced [kg/h]	~273	~12700

** Assumed electrolyzer consumes 55 kWh/kg_{H2} and 11 $Liters_{H20}/kg_{H2}$ when the turbine produces rated power.

During the preliminary analysis, the procedure for technology selection and definition of logical architectures was as follows. First, a set of lower-level requirements and functions were defined; then, potential technology alternatives were investigated; next, the alternatives were assessed through trade-off studies and multicriteria analysis; finally, interfaces between system functions were identified.

4.3.1 Technology Selection Criteria

For the technology selection and trade-off studies, different criteria considered relevant for the integration were defined. These criteria are summarized in Table 7 and further described as follows:

Table 7 Technological Selection Criteria

Criterium	Target*	Reasoning
Flexibility	↑	It is considered due to the fluctuating nature of the potential energy source (wind energy). Therefore, it is expected that the technology might be subject to start-ups/shut-downs and turn-down operations. Therefore, technologies with higher flexibility are favoured.
Weight	↓	It could potentially impact the installation and maintenance operations. The type of transport vessels, hoist equipment and operation time, are influenced, among several other factors, by the weight of the element that needs to be installed or maintained[15] (e.g. part replacement). Besides, the higher the weight, the higher the requirements on the support structure to host the equipment. Therefore, lower weights are favoured.
Footprint (Plot Area)	↓	Space availability in offshore support structures is limited. Current offshore turbines are reaching diameters at the tower base between 8-10 m [56, 57]. Larger footprints imply that more modifications in the support structure to accommodate the technology would be required. Therefore, compact technologies are favoured.
Maintenance Complexity	↓	In an offshore wind farm, maintenance activities are among the main cost contributors to the project[6]. Likewise, the higher the system's complexity, the higher the need of specialized personal and logistics required. Therefore, technologies with lower maintenance & complexity requirements are favoured.
Energy Requirements	↓	The system's primary function is to transform the captured wind energy into hydrogen. As this criteria directly impacts the system energy efficiency, technologies that consume or waste less energy are favoured. In addition, the criteria also consider the form of energy required. For example, some distillation and compression technologies require heat at a certain quality not available in an offshore context.
Technology Readiness	↑	Technology readiness is considered as it impacts the economic/technical realisability of the technological design. In this case, higher technology readiness is favoured.

*↑ : maximize - ↓: minimize

4.3.2 Offshore Wind Turbine

The main function of the offshore wind turbine system is supply the power needs of the electrolyser system and additional equipment needed for green hydrogen production using wind as a renewable energy source.

Requirements

As mentioned in section 4.1.1, the IEA 15 MW offshore wind turbine was set as part of the design basis for this project. For the design, it is assumed that the requirements needed to make a workable offshore wind turbine were already fulfilled during the conception of the said wind turbine. Therefore, the requirements defined in Table 8 are only focused on what is needed for integration with the electrolysis system(s).

Table 8 Wind Turbine Requirements for integration

Tag	Requirement
WT1	The wind turbine system shall transfer the produced power to the electrolyser system(s) and additional systems required for green hydrogen production
WT2	The wind turbine system shall be able to contain the integrated electrolyzer system (s) and additional systems required for green hydrogen production

The main technical characteristics for the reference turbine are shown in Table 9 (further details can be found in Table 26 in Appendix B.2) .

Table 9 IEA 15 MW Reference Turbine main Characteristic. Adapted from [58]

Parameter	Units	Value
Power Rating	MW	15
Turbine Class	-	IEC Class 1B
Cut-in Wind Speed	m/s	3
Rated Wind Speed	m/s	10.59
Cut-out wind Speed	m/s	25
Rotor Diameter	m	240
Hub Height	m	150

Logical Architecture

For the case of the offshore wind turbine, as a reference technology is already set, the functions identified in the previous section (see Figure 12) can be directly allocated to specific components. Figure 13 depicts the logical architecture of the components involved in the offshore wind turbine system. This architecture remains mostly very similar to a typical offshore wind turbine. However, some clear differences identified are the electricity power conversion steps and the mass & footprint that the support structure receives. The reasoning behind these differences is explained as follows:

In a typical offshore turbine, DC/AC converters [17], medium voltage transformers, and their respective medium voltage switchgear, among other elements, are typically present within the turbine to adapt the

[17] DC/AC conversion is typically part of a back-back converter which adjust the power frequency to the requirements of the grid.

electricity for transmission to an offshore substation. However, from the functional analysis, it is observed that these conversion steps are unnecessary when the produced power is directly supplied to an electrolyzer system, and therefore can be removed. Instead, the produced power must be conditioned to the specific electrolyzer requirements (such as voltage and current levesl). This power conditioning is further analysed during the integration analysis in section 5.5.

On the other hand, the support structure receives the additional mass & footprint from the electrolyzer system and additional required systems. Therefore potential modifications to the support structure are expected. However, these modifications are highly dependent on several variables such as the location of the electrolyzer system in the turbine, or the electrolyser's footprint & weight. The added footprint and weight of the electrolyser's system are estimated and further analysed during the integration analysis in section 5.5.

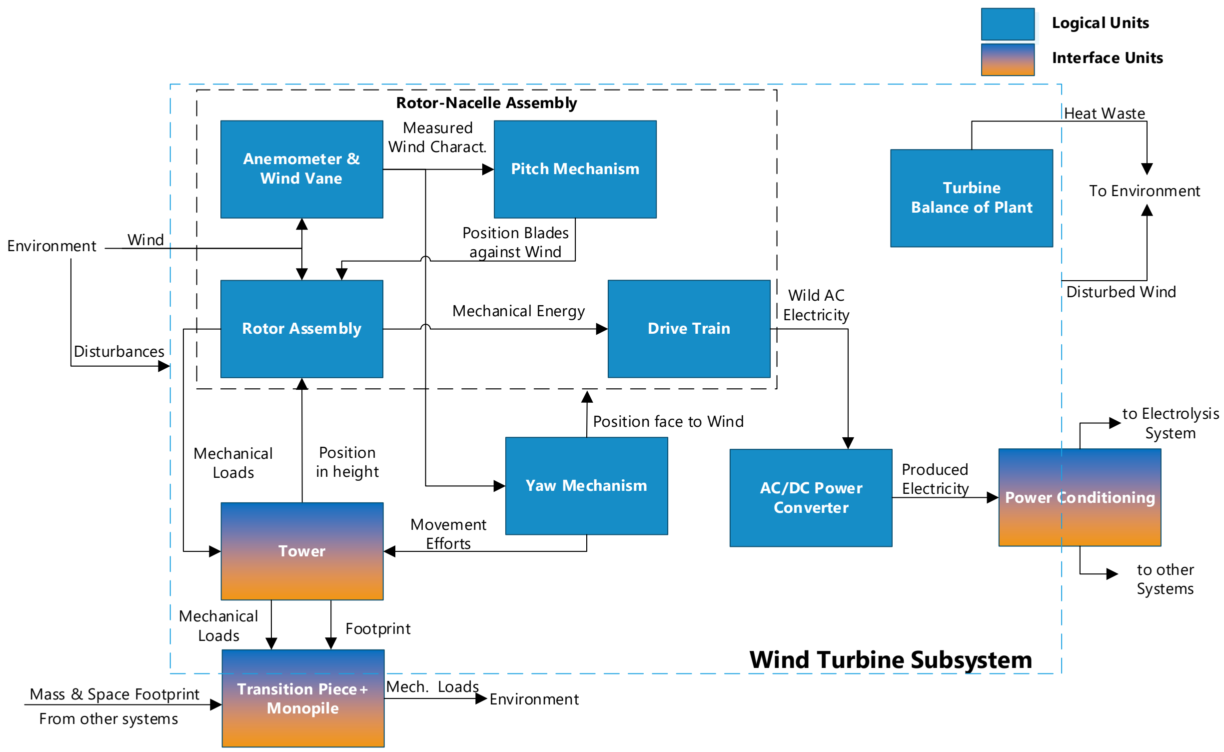


Figure 13 Wind Turbine Logical Architecture

Interfaces

For the wind turbine system, three primary interfaces with other systems are identified. The first interface corresponds to the power condition unit interfacing the turbine's produced electricity with the electrolysis system (and additional systems). Next, besides directly interfacing with the wind turbine tower, the support structure interfaces with the ground at which it is attached. Finally, the tower base also serves as an interface as it might contain part of the components of the other systems (e.g. power conversion units or the electrolyzer itself).

4.3.3 Electrolyzer System

The primary function of the electrolysis system is to produce hydrogen from water electrolysis.

Although the previous function can be performed by several technologies such as PEM, Alkaline and SOEC electrolysis, early in the design, PEM electrolysis was set as the preferred technology for the design. This decision was mainly based on flexibility and plant footprint criteria, in which PEM electrolysis resulted much more advantageous (see section 3.3.2).

Requirements

Table 10 enlist the identified requirements for the electrolysis system.

Table 10 Electrolyzer System Requirements

Tag	Requirement
SEI1	The electrolysis system shall produce hydrogen with a purity ~ 99.999* %V
SEI2	The electrolysis system shall ensure that water with conductivity < 1 µS/cm is fed into the electrolyzer stack(s)
SEI3	The electrolysis system shall condition the electricity supplied from the wind turbine to the requirements of the wind turbine, electrolyzer stack** and auxiliary systems.
SEI4	The electrolysis system shall ensure that the concentration of H_2 in O_2 and surrounding air remains outside the flammability range***.
SEI5	The electrolysis system shall handle the heat produced from the electrolysis process

* According to ISO Standard, Type 1 Grade D. This requirement is defined based on the targeted market application (Long-Haul Vehicles); ** e.g. required voltage & current levels ; *** Flammability range: 4 to 74% H_2 in air & 4 to 94% H_2 in pure O_2

Logical Architecture

Figure 14 depicts the logical architecture for the electrolysis system. This architecture is defined from the previous system's requirements, the functional analysis (see Figure 40 in Appendix B.1) and iterative validation with industry experts.

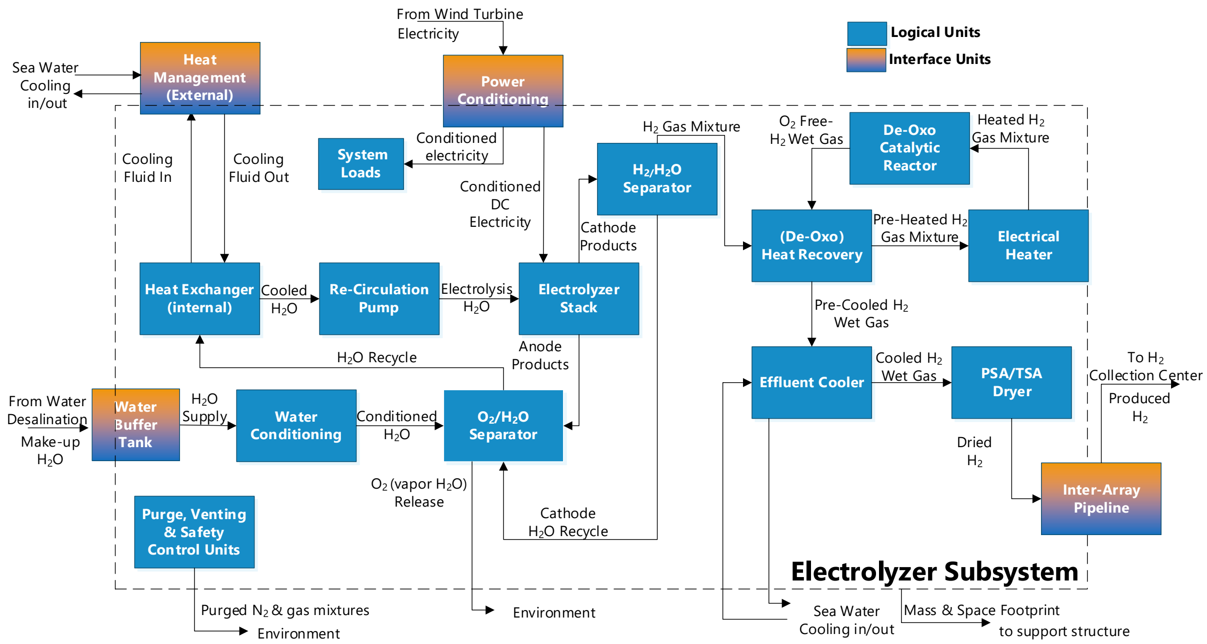


Figure 14 PEM Electrolysis Logical Architecture

The previous figure shows that besides the PEM electrolysis stack, the electrolysis system requires several other components for hydrogen production. Below a brief description of the logic in the diagram is given.

Desalinated water enters the system through a water buffer tank and is directed to a water conditioning unit[18] to purify the water until the required conductivity (*< 0.1 µS/cm)* is obtained. Next, the purified water is mixed with water from a process separator. The water from the separator is part of a recycling loop to handle the heat generated from the electrolysis process, whereas the water from the desalinator is make-up water to replace the consumed one during the electrolysis reaction.

The temperature of the mixed water (make-up + recycled) stream is adjusted (mostly cooled down) to the required stack temperature by transferring the heat to a cooling fluid in a heat exchanger (internal). Then, the cooling fluid further transfers the heat to the environment by using another heat exchanger (external). The external heat exchanger rejects the electrolyzer's heat using seawater as a cooling medium. In this regard, note that traditional onshore electrolyzer systems use air cooling for the final rejection of the electrolyzer's heat. However, this option has limited applicability in offshore environments due to deck area and ambient temperature constraints [59] and is therefore rejected.

The cooled water enters a pump that transfers it to the electrolyzer stack, where water occurs with the aid of DC electricity. The input electricity needs to be previously adjusted to the electrolyzer voltage and current requirement using a power conditioning unit. Note that although the main consumer of energy is the electrolyzer stack, some energy is also required to drive equipment such as pumps, heaters, controls, among others. These energy loads are not explicitly shown at this architecture level and are only depicted as system loads in the diagram.

From the electrolysis process, two main streams are generated, namely anode & cathode products. The anode product is a gas-liquid mixture, primarily composed of water with some oxygen product of the reaction (depending on the operating point, some hydrogen crossover also occurs). Therefore, the anode product is sent to a separator (O_2/H_2O separator) to recycle the water and remove the oxygen. On the cathode side, a saturated gas-liquid mixture mainly composed of hydrogen, water & traces of oxygen is fed into a separator(H_2/H_2O separator) to remove condensable water (the condensed water is transferred to the water recycling loop).

The resulting gas from the H_2/H_2O separator is mainly hydrogen, with small amounts of (vapour) water and traces of oxygen. However, this stream needs to be further treated to fulfil the purity requirements and transfer the hydrogen. Therefore, the produced hydrogen has the following purification steps: The traces of oxygen in the mixture are removed by reacting it with hydrogen in a de-oxo catalytic reactor. To favour the reaction, the temperature of the hydrogen gas mixture needs to be increased. This increase in temperature is performed in two steps: first, a heat recovery preheats the gas using hot gases from the de-oxo unit and then the preheated gas is sent to an electrical heater, where the temperature is further raised. The hot gas mixture then enters a de-oxo catalytic unit where the oxygen is converted into the water through a catalyzed H_2/O_2 reaction. Next, the oxygen-free mixture is pre-cooled in the heat recovery unit before entering an effluent cooler that further decreases the temperature. Finally, the cooled gas mixtures

[18] As the input water from the water desalinator to the electrolyzer system is set to be at drinking water quality, the water conditioned unit is composed mostly of second pass reverse osmosis and deionization units.

enter a dryer that removes vapour water for final hydrogen purification. The purified hydrogen is then transferred to a collection point through the inter-array pipeline for further compression and transmission.

During the component allocation, it is found that to avoid the generation of dangerous *O_2/H_2* gas mixtures[19] within the system, nitrogen purge is required, for the cold start-up of the system and prior to maintenance actions (which requires opening hydrogen piping or vessels). Purging nitrogen shall fulfil purity requirements according to the ISO 14175:N1[20]. In addition, as the electrolyzer system is likely to operate in an enclose environment (to protect it from the offshore environment), a HVAC control system tied with venting and safety control units are paramount to ensure that the system remains within the safety flammability limits.

Interfaces

Four primary interfaces with other system are identified: First, the power conditioning unit interfaces by receiving the produced electricity from the wind turbine generator and adjusting it to the electrolysis system requirements. Second, a buffer tank interfaces with the desalination system to ensure water supply to the electrolyzer stack (see section 4.3.4). Third, a heat exchanger circuit is added to reject the excess heat produced by the electrolyzer and interface with the environment—finally, the electrolyzer system interfaces with a centralized collection point by an inter-array pipeline to transfer the produced hydrogen. The decision to use an inter-array pipeline without an intermediate compression step is because the produced hydrogen has enough pressure to be transferred to a collection point near the wind farm (see discussion in section 4.3.5).

4.3.4 Water Desalination

The primary function of the water desalination system is to produce water for the electrolysis system for hydrogen production.

The boundaries that were defined for the water desalination system include intake and treatment of seawater to purify the water until at least drinking water quality levels (< 2500 µS/cm[21]). In this regard, it is essential to note that the electrolyzer stack operates with much stricter water quality requirements (e.g. conductivity <1 µS/cm) than what is defined as drinking water quality. However, it was decided to set this boundary in the water desalination system as current electrolyzer's vendors include a water purification step within the their product package[22]. This boundary although specified here, is not a requirements. Therefore, future stages of design could consider merging water desalination and water purification in a single system.

[19] Flammability range: 4 to 74% H2 in air & 4 to 94% H2 in pure oxygen

[20] From discussion with product vendor's

[21] 2500 µS/cm is the limit as per the Directive (EU) 2020/2184. Typical conductivities are ~ 50-500 µS/cm

[22] Currently, electrolyser vendor's include water polishing as part of their electrolyzer package

Requirements

Table 11 enlist the identified system requirements for water production. These requirements are derived both from the PEM electrolyzer technical specifications and the operational context of the system.

Table 11 Water Desalination Requirements

Tag	Requirement
SSW1	The desalination system shall produce water with at least drinking water quality*
SSW2	The desalination system shall ensure reliable and on-demand water supply to the electrolyzer
SSW3	The desalination system shall be able to operate with North Sea typical input quality **

* From discussion with PEM electrolysis vendors. Directive (EU) 2020/2184 can be used as a reference
** North Sea TDS~32000 PPM (~5 S/m)

Trade-Off Analysis

At this phase of design, it is not clear which technology will be used to fulfil the function of water production as several alternatives in the market can be used for water desalination. Some of these alternatives, such as Reverse-Osmosis (RO) and Mechanical Vapour Compression (MVC), require electricity for water desalination. In contrast, alternatives such as Multi(or single)-Effect Distillation (MED)[23] and Multi-Stage Flash Distillation (MSF) require a heat source for water desalination. A general description of these technologies can be found in Appendix B.3.

To identify a suitable technology for the system under design, trade-off studies were performed. For this aim, a market screening was performed to identify the current characteristics of the desalination technologies (see Table 29 in Appendix B.3); next, an analysis of the technology's advantages and drawbacks based on literature and product vendor's input was made and is summarized in Table 12. From this analysis, the different desalination technologies were compared using the selection criterium of flexibility, maintenance & complexity, weight, footprint and energy requirements as defined in Table 7. The analysis serves as a support for the technology selection using a Multicriteria Assessment (MCA) performed at the end of this section.

[23] Single effect also possible. Multiple Effects are used when high thermal efficiency is needed

Table 12 Trade-Off Analysis Water Desalination [60, 61, 62, 63]

Technology	Advantages	Drawbacks
Reverse Osmosis (RO)	• Low electricity requirements (when no heat source is available) • Modular design (which allows scalability)	• Higher water pre-treatment requirements than other technologies • Potential membrane fouling • Cannot operate intermittently due to the impact of high-pressure changes on the membrane • Lower product purity (~300 ppm) than thermal technologies (~5 ppm)
	Maintenance Requirements*: Filter replacement every three months; annual overhaul (2 days duration for small systems); Osmosis membrane replacement every four years. Weight: 25 $kg/m^3/day$; Footprint: 0.08 $m^2/m^3/day$	
Multi (Single)-Effect Distillation (MED)	• Turndown ratio (~50 % capacity) • Can handle sudden operating changes • High product purity (~5 ppm) • Can operate at relatively low temperature (70-90 C) • Lower pre-treatment requirements than RO • Lower specific energy consumption than MSF	• Requires more complicated circuitry than Multi Stage Flash Distillation • Risk of scaling with increased operating temperatures. However, less than MSF (once through the process)
	Maintenance Requirements*: 2-3 visits for cleaning in place (3-4 h duration)—regular checking of pumps & instruments. Weight: 65 $kg/m^3/day$; Footprint: 0.02 $m^2/m^3/day$	
Mechanical Vapour Compression (MVC)	• High operating flexibility** • High product purity (~5 ppm) • Lower pre-treatment requirements than RO (mostly anti-scaling)	• Unit size is limited to compressor capacity (currently: 5000 m^3/day)* • Higher investment cost than other thermal technologies • Higher electrical requirements than reverse osmosis
	Maintenance Requirements*: 3-4 visits for cleaning in place per year. General overhaul once a year. Every 3 years major compressor overhaul and replacement of bearing blocks Weight: 55 $kg/m^3/day$; Footprint: 0.09 $m^2/m^3/day$	
Multi-Stage Flash (MSF)	• Simplest technology • High Product purity (~5 ppm)	• Requires precise pressure control • Require external heat source & electricity to operate • Turndown ~60% rated capacity • Requires heat at T > 90 C for operation (higher risk of scaling)
	Maintenance Requirements & Weight: No vendor's information, assumed similar than MED Footprint: 0.02 $m^2/m^3/day$ (large scale)	

*Relevant when large scale desalination is considered for centralized wind farm electrolysis
** Operating with variable renewable energy sources has been demonstrated

Flexibility

For the water desalination system, flexibility was considered in terms of the assessed technology turndown's capacity and its ability for intermittent operation.

In this regard, Mechanical Vapour Compression (MVC) scored the highest as discussion with product vendors confirmed that these units can be adapted to match wind's availability. In addition, the integration of MVC with variable energy sources, such as wind, have been reported in demonstration projects [64, 65].

On the other hand, Reverse Osmosis (RO) scored the lowest as discussions with RO vendors revealed that intermittent operation of this unit is not recommended (switching the system on/off is shall be minimized). The reason that the high-pressure changes (RO operates at ~60 bar) resulting from the intermittent operation might damage the RO membranes. Besides, product vendors report that turndowns to 80% of the rated capacity are possible but not the preferred state (to preserve the life of the membranes).

Discussions with multi[24] (and single) effect distillation product vendors confirmed that turndown capacity as low as 50 % of the rated capacity are possible. Operation below this threshold is not recommended as it could result in dry equipment in which scaling could accelerate. In addition, continuous switching on/off is not expected to have a significant impact on the lifespan in the system, although relatively slow star-ups (8-10 min) for the system could be expected (primarily due to the time required to warm up).

For the case of Multi-Stage Flash distillation no response in terms of flexibility was received, however, this technology was scored low in terms of flexibility as turndowns capacity of ~ 60 % of rated capacity reduced flexibility due to precise pressure control requirements have been reported in literature.

Although at this point, Mechanical Vapour Compression appears to be the sole suitable option for the system in terms of flexibility. The other alternatives are not discarded, as a buffer tank can be added to the system to handle the fluctuations in water demand. The buffer tank can also be designed with sufficient capacity to minimize the start/stop cycles and thus facilitate using technologies such as reverse osmosis.

Energy Requirements

From the thermal options, Multi Stage Flash(MSF) and Multi(or single)-Effect Distillation (MED) require a heat source for operation. Although a heat source is not directly available for utilisation in the offshore context, discussions with stakeholders suggested reutilising the waste heat from electrolysis for desalination. However, the primary concern for this alternative is that the current PEM electrolysis process operates at moderate temperatures (50-60 ^{o}C) that might fall short of the minimum quality of the heat source used in the mentioned desalination processes (typically medium/low-pressure steam or heat sources above 70 ^{o}C).

MED product vendors indicated that their standard units require at least a heating medium at 70 C for operation and that whereas going to lower temperatures could be possible, it will undoubtedly impact the size and weight of the units, as a larger heat exchange area would be required for waste heat utilisation. In addition, note that the principle of operation of these technologies is first to evaporate the water under

[24] Multi-effects are performed to increase the heat recovery effiency of the system

vacuum conditions and then condensate (with a cooling media) the cleaned water in a separate chamber. The operation at lower temperatures is reflected in a vast increase of cooling required for condensation.

From discussions with TNO experts, another potential concern of using thermal base technologies is that at a low electricity production period (due to low wind speeds), waste heat may not even be available to maintain optimal electrolysis temperature as the electrolyzer system would become more efficient. Therefore, extra heat would be required to be generated by converting power from the turbine into heat. Although this option is technically possible, it will increase the system's complexity as not well-balanced heat (due to the power fluctuation) is available.

On the other hand, technologies such as Mechanical Vapour Compression(MVC) and Reverse Osmosis (RO) require electricity for operation (that would need to be supplied by the wind turbine). In general, RO operates at low temperatures, without the need for phase change (evaporation). The previous characteristics make this RO much less energy-intense than MVC.

Maintenance & Complexity

The highest weight factor was given to this criteria as maintenance operations of the wind turbine are one of the main cost contributors in a wind farm project. As a reference, calendar base maintenance operations of an offshore turbine are ideally in the range of 1 to 2 visits per year [6].

In this regard, all technologies have minimum scheduled intervention requirements (see Table 12) that might impact the calendar base maintenance operations. For all the technologies, at least 3-4 visits per year are expected. For example, in the case of Reverse Osmosis (RO) to perform activities such as inspections and filter replacement, whereas for Mechanical Vapour Compression and Multi-Effect Distillation (MED) to perform inspections and activities such as cleaning in place of the equipment.

Initially, RO was considered the most maintenance-intensive unit as, besides scheduled visits for filter replacement, major membrane replacements were expected every four years. On the other hand, MVC was initially considered less maintenance intensive, as only yearly overhaul, especially for bearings lubrication, was reported in the literature [20]. However, the score assigned to this technology was refined after discussion with MVC vendors, which reported general overhauls once a year and a major overhaul every three years for the compressor and to replace bearing blocks.

From the previous insights, it is clear that some extra efforts are required in any of these technologies to ensure the proper integration with the wind turbine. For example, larger filters or spare filters (with automatic switching) could be used on the Reverse Osmosis to decrease the maintenance intervals. Likewise, for the Multi (or single) Effect distillation and the Mechanical Vapour Compressor cases, automation of the cleaning processes would be required to decrease their maintenance intervals.

In any case, there will be certainly a penalty cost to make any of the desalination technology suitable for the integration with the wind turbine electrolysis systems. However, there are certainly options to overcome this maintenance issues.

Weight & Footprint

Finally, in terms of weight & footprint, it is found that at the scale at which the water is required to be produced in the wind turbine (< 100 m^3/day) [25], all the technologies (except MSF) have relatively compact (areas < 5 m^2) and low weights (2 - 10 tonnes), see Table 29 in Appendix B.3. In particular, Reverse Osmosis having the lowest weight according to product vendors. For the case of MSF, the minimum capacity found for these plants was 1500 m^3/day, which is far above the turbine's requirement.

Reference Cost

Reference cost was initially considered as a criteria for water desalinisation selection. However, after discussing with Reverse osmosis and Multi Effect Distillation product vendors, similar CAPEX costs were given for both systems (~3000 €/m^3/day), which is much larger of what is reported in the literature for these systems (~800-1500 €/m^3/day) [66, 67, 68]. According to the product vendors, the significant price difference with literature is due to the relatively small scale of the units. Therefore, this criteria was not considered.

Concept Selection

The previous analysis were used as a basis for the Multi-Criteria Analysis (MCA) in which a performance matrix is used for concept selection. In this matrix, except for the footprint & weight , each criteria was scored in the range from 1 (worst) to 10 (best). Besides, in order to bring the criterion to a common scale, each of them were normalized with a sum-based normalization technique [69]. The assigned scores and weighting factors were refined based on discussions with industry experts and product vendors insight. The performance matrix, weighting factors and resulting normalized scores are shown in Table 17.

Table 13 Normalized Scores Water Desalination MCA

Performance Matrix					
Criterion	**Weight Factor**	**MSF**	**MED**	**MVC**	**RO**
Footprint [m^2/m^3/day]	0.15	0.03	0.02	0.09	0.08
Weight [kg/m^3/day]	0.15	65	65	55	25
Flexibility [-]	0.20	4	6	9	5
Energy Requirements [-]	0.20	2	2	7	9
Maintenance & Complexity [-]	0.30	5	6	5	4
Normalised Score		0.20	0.26	0.27	0.27
MSF: Multistage Flash, RO: Reverse Osmosis, MED: Multiple-Effect Distillation, MVC: Mechanical Vapor Compression ; [-] → Score Range: 1 (worst) – 10 (best)					

Reverse Osmosis (RO) & Mechanical Vapour Compression (MVC) scored the highest rating among the analysed alternatives. Among these two alternatives, RO performed better in terms of energy efficiency, footprint & weight criteria, whereas MVC performed better in terms of flexibility. In terms of maintenance requirements, both technologies had their particular drawbacks that will undoubtedly impact the maintenance strategy of the turbine (and wind farm).

[25] This water requirements for the turbine are comparable to small scale applications (e.g. ships)

The final decision was to continue with RO for the design, as the buffer tank could technically handle its flexibility disadvantage, and still this technology has advantages in the other criteria. However, MVC should not be fully discarded as later design stages could reveal more advantages (or disadvantages) of this unit.

Logical Architecture

Figure 15 depicts the logical architecture for the water desalination system. This architecture is derived from the requirements and the functional analysis of this system (see Figure 41 in Appendix B.1).

In this system, seawater from the environment goes through a strainer to filter large elements in the water inflow; the seawater is then pumped to filter screens to remove coarse and fine particles. Next, the screened water is raised in pressure before it passes through the reverse osmosis membranes, where dissolved impurities are removed. The reverse osmosis generates two streams, namely distilled and brine (concentrated water). The purified water is fed to a buffer tank for later utilisation in the electrolysis process, whereas the concentrated water is rejected back to the environment. The buffer tank helps manage fluctuations in water demand and minimize continuous starts/stops of the unit. Finally, the active carbon packages are used to clean the membranes by flushing them in the reverse direction (daily) with part of the clean water.

Note that the reverse osmosis process typically requires pre-treatment of the seawater through the dosage of anti-scalant (to prevent that particles accumulate and plug the membranes pores). However, discussions with product vendors indicate that at this small scale is rather difficult to perform the injection and thus the dosage requirement is avoided by accepting lower recovery rates (which reduces the salinity of the brine).

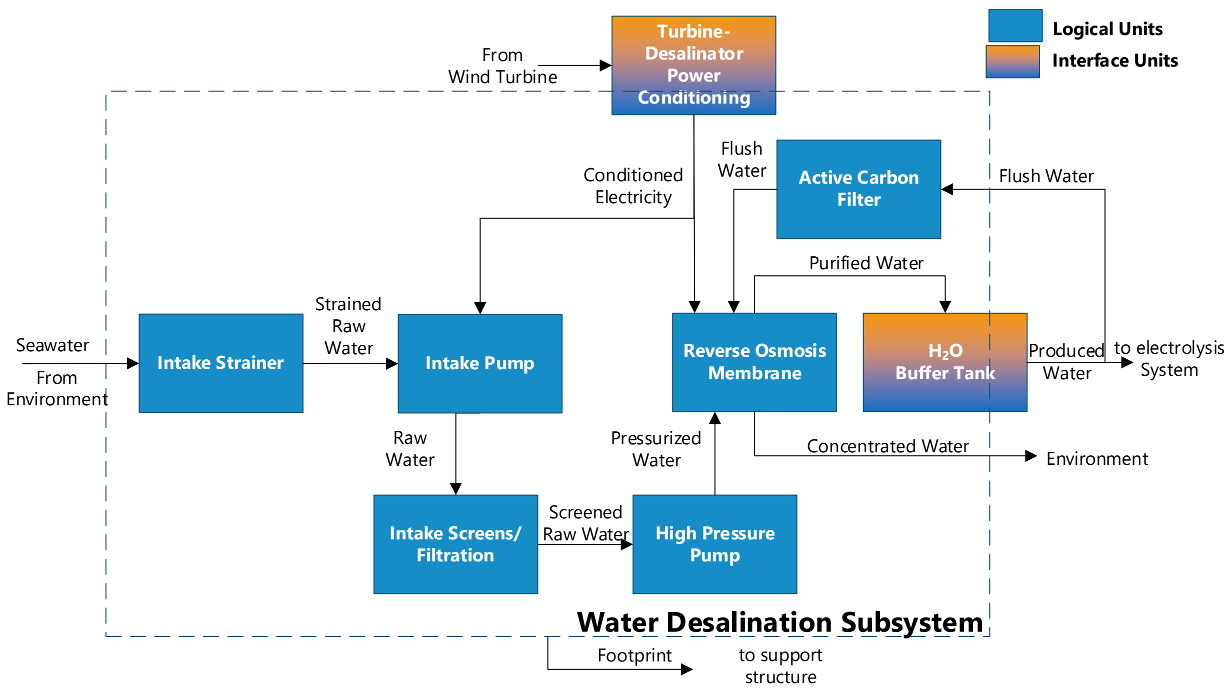


Figure 15 Water Desalination Logical Architecture

Interfaces

For the water desalination system, three primary interfaces with other systems are identified. First, like the electrolysis system, a power conditioning unit interfaces the power incoming from the wind turbine to be suppied to the desalination process. On the other hand, a water buffer tank serves as an interface for the produced water that is to be used in the electrolysis system. Finally, the system interface with the environment through the intake of seawater and the rejection of concentrated water.

4.3.5 H_2 Transfer & Compression

The primary function of the H_2 Transfer & Compression system is to transfer the produced hydrogen from the turbine to a centralized collection point where it would be compressed to higher pressures for further transmission.

For this specific system, early in the design stage, it was observed that compression in the turbine-electrolyzer plant would not be required, but instead, centralized compression would be preferred because:

- The electrolysis system already produces pressurized hydrogen (~30 bar), which might be enough to transfer the hydrogen to a centralized collection point
- Economies of scale apply to traditional compression systems. Besides, centralized compression reduces the number of compressor units and thus the complexity of the system.
- Area footprint could be liberated at the turbine. Although the footprint is transferred to the collection point, scaling up the compressor, typically result in smaller areas per gas compressed.

To verify whether the hydrogen could be transferred from the wind turbine to a centralized collection point, an estimation of the hydrogen pressure losses due to friction in a straight pipeline was performed. The estimation was made assuming that the maximum distance (and thus pressure loss) for the gas being transferred is for a pipeline installed between a collection point adjacent to the 700 MW wind farm and a 15 MW wind turbine that is on a corner on the opposite side of the farm (See assumptions in Table 33 in Appendix B.4). The results indicate that when the turbine operates at rated capacity, it is possible to transport the maximum amount of hydrogen with pressure losses < 1.5 bar while using a relatively small pipe diameter ($Ø_{pipe}$ ~ 4 in). Therefore, to take advantage of the previously mentioned benefits, centralized compression was selected for the design. This decision implies that the hydrogen flow rates at the wind farm scale (see Table 6) would be used for compressor selection.

Note that although centralizing compression implies that this system is outside the original limits of the project. However, technology selection of the compression system is still assessed for completeness of the system design and because it is helpful during the economic assessment.

Requirements

Table 14 enlist the identified system requirements for hydrogen transfer and compression.

Table 14 Hydrogen Transfer & Compression Requirements

Tag	Requirement
SSC1	The produced hydrogen shall be delivered to a centralized gathering point located at the vicinity of the wind farm
SSC2	The compression system shall raise the hydrogen's pressure to at least 100 bar to transmit the produced hydrogen to shore*
SSC3	The compression system shall maintain the hydrogen purity
SSC4	The compression system shall be able to operate with a variable supply of hydrogen
*This requirement is defined based on current operating pressures (70-100 bar) of onshore H_2 gas pipelines **[54, 9]** at which the produced hydrogen would be expected to be injected . The final required pressure is also a function of the distance to shore of the wind farm as pressure losses need to be compensated. Here 100 bar (compression ratio slightly > 3) was used as a reference.	

Trade-Off Analysis

Several technologies could be used for hydrogen compression, such as: dry/lube-oil Reciprocating, Diaphragm, Ionic Liquid, Metal Hydride, centrifugal and Electrochemical Hydrogen Compressor (EHC). A brief description of these technologies can be found in Appendix B.4.

To identify a suitable technology for the system under design trade-off studies were made. For this aim, a market screening was performed to identify the current characteristics of the compressor technologies (see Table 32 in Appendix B.4) ; next, an analysis of the technology's advantages and drawbacks based on literature and product vendor's input was made and is summarized in Table 15. From this analysis the compression technologies were compared in terms of flexibility, maintenance & complexity, weight, footprint, energy requirements and technology readiness as defined in Table 7. The analysis served as a support for the technology selection performed at the end of this section.

Note that lube-oil reciprocating compressors were discarded early in the design, as the oil reduces the quality of the produced hydrogen, therefore conflicting with the requirement SSC3 for this system. On the other hand, centrifugal compressors for this specific application (high purity hydrogen compression) were also discarded early in the design. The reasoning for this decision is the current limitations/challenges that this technology has for handling low molecular-size gases such as hydrogen. For example, to achieve reasonable pressure ratios high impeller operating speeds are required[26]. However, the maximum operational speed is constrained from an structural point of view by the mechanical strength limits of the impeller(which directly correlated with the operational tip speed) [70, 71]. Although the mechanical strength limits vary depending of the material used, the amount of materials compatible for this service are also limited due to the potential of hydrogen embrittlement[27]. Alternatively, increasing the pressure ratio while maintaining the operational speed would require several additional compression stages. As a reference, for pure hydrogen, 11 centrifugal stages are needed instead of 1 reciprocating stage for a modest pressure ratio of 3 [72]. The large amount of stages increases complexity, Capex, and lower the efficiency

[26] For a given impeller tip speed the pressure increase is directly proportional to the compressed gas molecular weight [46].

[27] Hydrogen diffuse into the alloy reducing its ductility and load bearing capabilities. This embrittlement leads to early failures which can result in unacceptable levels of safety [43]

of this technology. The previous difficulties have currently limited the commercial availability of these machines for high purity hydrogen applications (and high pressure ratios). However, some efforts [73, 70] are being made to improve this technology and therefore it could be reconsidered in the future.

Table 15 Trade-Off Analysis Compression [74, 75, 76, 77, 78, 79]

Parameter/ Technology	Advantages	Disadvantages/Challenges
Reciprocating (oil-free)	• Larger capacity per unit than reciprocating compressors • Relatively long MTBO[1] (~12000h) • Can adjust to varying suction/ discharge pressures	• Manufacturing and maintenance complexity (several moving parts) • Difficult thermal management • Vibration/noise • Risk of H_2 leakage on sealing rings • Large capacities currently limited to pressures up to (~200 bar)**
	Efficiency: ~65 %; Footprint:~ 0.03-0.1 $m^2/(kg_{H2}/h)$; Weight[a]: 12 - 26 $kg/(kg_{H2}/h)$	
Diaphragm	• Improve thermal management compared to reciprocating compressors • High pressures attainable without compromising H_2 purity • Adaptable to high pressures	• Diaphragm is prone to failure (specially at high flow rates) • Currently lower capacities per single unit than piston • Intermittent operation can impact diaphragm lifespan • Shorter MTBO (~4000 h) than reciprocating compressors
	Efficiency: 65-85 %; Footprint[a]:~ 0.1 $m^2/(kg_{H2}/h)$; Weight: No vendors information	
Ionic Liquid	• Can adjust to varying suction/discharge pressures • High compression ratios • High energy efficiency • Expected lower maintenance requirements than reciprocating compressors as it has fewer moving parts	• Potential leakage of ionic liquid • Potential risk of cavitation phenomena • Currently, ionic liquids are expensive • Relatively new technology
	Efficiency: 90 %; Footprint[a]: ~ 0.2 $m^2/(kg_{H2}/h)$; Weight[a]: 257 $kg/(kg_{H2}/h)$	
Metal Hydride	• No moving part (=fewer failures) • Simple design • No noise	• Require moderate quality of heat source to operate (90-150 C) • Slow compression dynamics • Low thermal efficiency.
	Efficiency: ~10 % (thermal); Footprint[a]:~ 5.1 $m^2/(kg_{H2}/h)$; Weight[a]: 780 $kg/(kg_{H2}/h)$	
Electro-Chemical	• No moving parts • Potential lower maintenance requirements than reciprocating compressors • Flexible operation	• Membrane degradation • Currently, low capacities per unit • Complex water management requirements
	Efficiency: ~80 %; Footprint[a]:~ 1.5 $m^2/(kg_{H2}/h)$; Weight[a]: 1015 $kg/(kg_{H2}/h)$	

*Mean Time Between Overhaul; ** For high capacities and pressure ratio a combination with diaphragm could be used

[a] At current (2020) maximum capacity per unit. Multiple units in parallel would be needed to attain farm capacity

Weight & Footprint

In terms of weight & footprint, dry reciprocating compressors are currently the only technology that can handle the wind farm flow rates (~12700 Kg/h) while benefiting from economies of scale. On the other hand, Metal Hydride, Ionic Liquid & Electrochemical Hydrogen compressors are currently limited to handle very low processing capacities. Except for Ionic Liquid, these compressor technologies use a modular approach to increase capacity, which would result in several units in parallel (increasing footprints and weight) to handle the flow rates at the wind farm level. For the case of Ionic Liquid, no contact with products vendors could be made to determine potential limitations of further scale-up this technology.

For the diaphragm compressors, discussions with product vendors resulted that this technology also has limitations to handle the processing capacities at the wind farm scale. The reasoning for this limitation is the reduced movement of the diaphragm (restricted by the stiffness and strength of the diaphragm), limiting the amount of volume that can be transported. According to product vendors, increasing the diaphragm size is possible (until certain manufacturing liming); however, it can quickly reach a point where the diaphragm size is too large that this technology becomes not economically competitive.

Flexibility

In terms of flexibility, the reciprocating and ionic liquid compressors can handle the expected variable gas flow input (from the wind fluctuations). There are several alternatives to control the flow in these compressors (e.g variable speed control, Hydrocom). Likewise, Electrochemical Hydrogen Compressors (EHC) scored high as this technology has similar flexibility capabilities to the electrolyzer system.

From discussions with product vendors, diaphragm compressors scored low in this category as there is a risk of diaphragm failure when an intermittent operation occurs (which applies to the design case).

Maintenance Requirements

Regarding maintenance requirements, rotating equipment such as piston oil-free and diaphragm compressors scored the lowest in this category due to the high level of complexity and moving parts that these systems involve. In particular, discussions diaphragm vendors indicate Mean Time Between Overhaul (MTBO) of around 4000 operating hours, which is shorter than the reported for reciprocating compressors (~8000 operating hours). On the other hand, Ionic Liquid compressors are expected to have fewer maintenance requirements than reciprocating and diaphragm compressors as it has fewer moving parts Besides, the liquid used in the ionic compressor is not prompt wear & tearing unlike the piston used in the reciprocating counterparts.

For the case of Metal Hydride and Electrochemical Hydrogen Compressor (EHC), the main advantage in this category is that these technologies do not require moving parts for compression, resulting in lower maintenance costs and high uptime. However, according to EHC vendors reports, the main element to fail is the membrane electrode assembly (MEA), which needs to be replaced every five years, reducing the score assigned to this technology.

Technology Readiness

In this criterion, reciprocating (oil-free) & diaphragm are proven technology that has relatively high maturity in the market, whereas ionic liquid, Metal Hydride, and Electrochemical Hydrogen Compressors are in the demonstration phase.

Energy Requirements

In terms of energy requirements, Metal Hydride Compressors utilise heat to perform hydrogen compression. Although a heat source is not directly available for utilisation in the offshore context, discussions with stakeholders also suggested reutilising the waste heat from electrolysis to drive this technology. However, after investigating the operating characteristics of this technology, it is found that the quality of the produced heat by the electrolysis system (T~60 C) is not sufficient to drive this kind of technology (Operating Temperatures~ 90-150 ^{o}C) at the current state of the art.

Electrochemical Hydrogen Compressors & Ionic Liquid compressors are reported to be highly efficient in terms of energy usage as they approximate more an isothermal operation than other technologies and therefore scored high in this criterion.

Technology Selection

The previous analysis was used to perform the Multi-Criteria Analysis (MCA) to score the technologies in terms of performance for the selection criteria. Except for the criterion footprint & weight, the score was given in the range from 1 (worst) to 10 (best). To bring the criterion to a single scale, they were normalized with a sum-based normalization technique [69]. The performance matrix, weighted factors and the resulting normalized scores of these analyses are shown in Table 16.

Table 16 Normalized Scores Compression MCA

Performance Matrix						
Criterion	Weight Factor	Reciprocating (Oil Free)	Diaphragm	Ionic Liquid	EHC	Metal Hydride
Footprint* [$m^2/(Kg_{H2}/h)$]	0.15	0.03	0.1	0.2	1.5	5
Weight* [$kg/(Kg_{H2}/h)$]	0.15	12	500	257	1015	780
Flexibility [-]	0.20	8	3	8	8	2
Energy Requirements [-]	0.10	6	7	9	8	3
Maintenance & Complexity [-]	0.20	2	4	6	7	8
Technology Readiness [-]	0.20	8	7	3	3	3
Normalized Score		0.39	0.16	0.16	0.15	0.14
* At current (2020) maximum capacity per unit; [-] → Score Range: 1 (worst) – 10 (best)						

In this case, reciprocating (oil-free) compressors scored the highest among the analysed alternatives and are the selected technology for the design. The main concern of using reciprocating (oil-free) compressors is the high maintenance requirements (derived for the several amounts of moving parts) which can potentially reduce the availability of this system. However, after discussion with industry experts, it is suggested to tackle this drawback by having an arrangement of at least 2 compressors, each sized to handle 50 % of the farm production (of hydrogen) plus one spare compressor (also sized for 50 % production).

Logical Architecture

In this case, the compression system is placed at the centralized compression point and is treated as a vendor's package. As a result, hydrogen transfer is reduced to use an inter-array pipeline that connects the turbine to the collection point, for which no further logical decomposition is required at this stage of design.

Interfaces

The primary interfaces for the H_2 transfer and compression system are the inter-array pipeline that connects the hydrogen output at the purification step of the electrolysis system with the compressor system input at the entrance of the collection point. On the other hand, the compressor system will interfaces with the gas network through an export pipeline.

4.3.6 Back-up Power

Backup power is required for communications, air conditioning and a number of safety instruments and protective equipment during extended periods of no wind or wind turbine outage. This system's energy & power requirements depend on the specific weather conditions of operation (e.g. frequency & length of electricity unavailability).

4.3.7 Overall System Architecture

Once the system's functions are defined and preferred technologies to perform these functions are allocated, it is then possible to establish the logic sequences and interaction stages to fulfil the system's objectives. Figure 16 depicts the resulting system logical architecture.

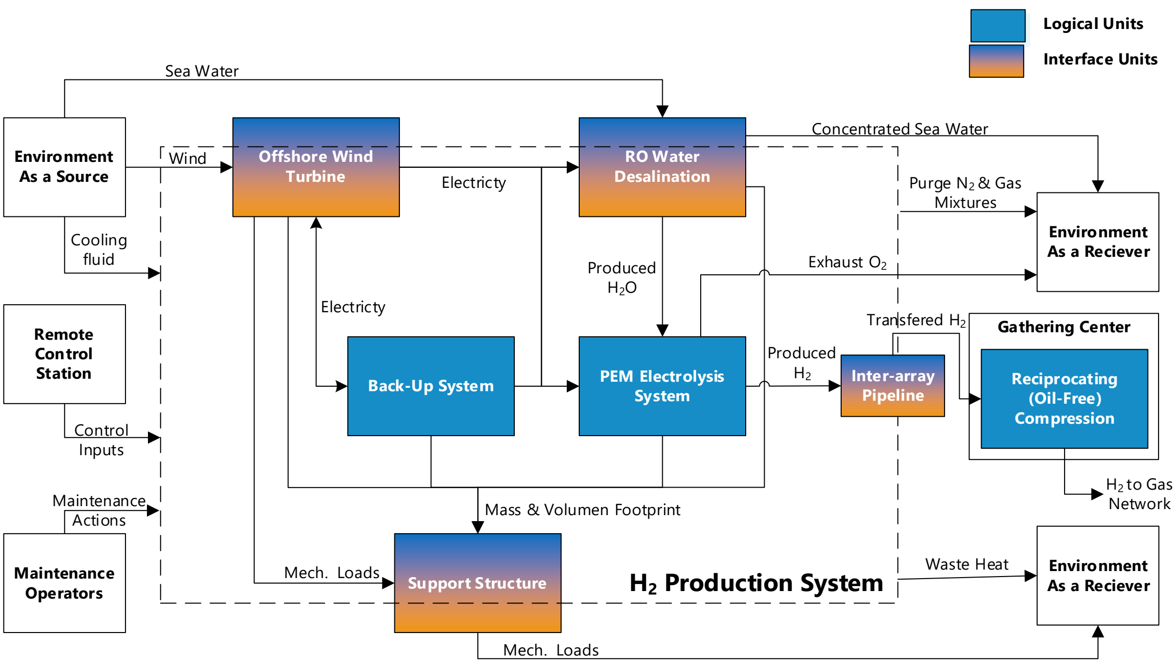


Figure 16 Overall System Architecture. System View

4.4 Summary of findings

In this section, a preliminary analysis following the system engineering methodology was performed. The key findings and design choices of this analysis are summarized below:

• Offshore Wind Turbine: The IEA 15 MW offshore wind turbine and a ~700 MW wind farm are set as a reference for the system design. Key interfaces are the electrical connection between the generator and the electrolyzer system and the support structure with the electrolyzer and other added systems.

• Electrolysis System: A deep analysis of the PEM electrolysis (previously set as the preferred technology) allowed identifying numerous set of components required to ensure hydrogen production. Critical requirements are the water quality fed to the electrolyzer, heat remotion, power quality/characteristics fed to the electrolyzer and hydrogen purity.

• Water Desalination System:

- Technology: Reverse Osmosis is selected as the preferred option to produce water for the electrolysis process. This technology resulted advantageously in terms of reduced footprint and higher energy efficiency. However, due to its low flexibility, interfacing with the wind turbine-electrolysis system requires the addition of a buffer tank to manage the fluctuations in water demand and power supply.
- Maintenance: The current maintenance requirements of Reverse Osmosis technology conflict with the expected maintenance schedule of an offshore wind turbine. However, engineering around the RO maintenace activities by using spare components or larger units could help mitigate this issues.
- Quality Boundary: Current desalination systems do not produce water at the required electrolysis quality levels. Therefore, as in an onshore electrolysis system, further water purification is required. In the design, the final water purification step is considered part of the electrolysis system boundaries and not the desalination system. Future optimization can include designing a water production system that includes water desalination and purification within the same boundaries.
- Waste Heat Utilisation: Waste heat from the electrolyser was suggested to drive the water desalination (thermal options) and the compression (Metal Hydride) processes. However, the quality of the produced heat is currently insufficient for those applications. The waste heat is then drained into the environment by use of a heat exchanger with sea water.

• Compression System:

- Location: The operating pressure of the PEM electrolysis (~30 bar) is sufficient to deliver the produced hydrogen to a centralized collection point in the vicinity of the wind farm. In this collection point, centralized compression is set to be performed to transfer the hydrogen to shore. Centralized compression was chosen to free space (and reduced weight) at the hydrogen turbine and take advantage of economies of scale of compression systems.
- Technology: reciprocating (Oil-Free) compressor has been selected as the preferred technology as it is the sole that can handle the flow rates needed at the wind farm level. Prospective technologies such as electrochemical compressors, ionic liquid, and metal hydrides are not sufficiently scaled up to handle hydrogen flow rates at a wind farm-scale. Alternatives, such as diaphragm, have limitations in scalability and intermittent operation.
- Compressor Arrangement: An arrangement of at least 2 compressors, each sized to handle 50 % of the hydrogen-wind farm production plus one spare compressor (also sized for 50 % production) is suggested to handle the maintainability drawbacks of the selected reciprocating compression technology.

5 System Integration Assessment

In this section, a technical assessment of the integrated system is performed. For this aim, first, the electrolyzer characteristics, electrochemical model, and wind site characteristics used for the design are defined and analysed. Next, the operational compatibility of the offshore wind turbine concerning the operational flexibility of the electrolyzer system are explored. Then sizes of the main equipment are estimated, and potential opportunities for footprint reduction are discussed. Next, a rough estimation of the added weight of the system and its potential impact is analyzed. Finally, two concepts for wind turbine integration are generated and analyzed. Finally, a concept for integration is selected.

5.1 Electrolyzer Design Baseline

As a baseline for the design, a closer look at the PEM electrolysis system is performed. For this aim, an exhaustive search of the electrolyzer characteristics and operating conditions were collected from discussions with industry experts, product vendors and literature. Table 17 summarises the relevant characteristics defined, their expected future value and the reasoning behind it.

Note that during the design, the "current in the market" technology characteristics shown in Table 17 were used to estimate the performance characteristics of the electrolyzer system, perform material balances, and equipment sizing.

Table 17 Base Design Characteristics PEM Electrolyzer

Parameter	Current In the Market	Future Expected	Reasoning
Electrode Effective Area $A_{cell,effective}$ [cm^2]	~1500	3000-5000	Larger areas within expected membrane manufacturability limits [46, 6].
Stack Operating Temperature T_{stack} [C]	~55	70-80	Variable among product vendors; Limitations of operating at higher temperature is due to membrane degradation.
Max Stack Temp. Increase $\Delta T_{stack,max}$ [K]	5	10	Above ΔT of 10 K, thermal stress leads to membrane degradation and increased ageing rates [80].
Operating Pressure H_2 Side $P_{stack,H2}$ [bar]	~30	<70	At higher pressures, the H_2 crossover increases, impacting the minimum operating load for safe operation [21]. Besides, more expensive materials are required at higher pressures [6]. Large differential pressures impacts the mechanical stability of the membrane in the PEM Electrolyzer [6] Expected operation up to 70 bars. However, there is room for improvement. For example,

			small scale (kw) system's at pressures up to 165 bar have been tested in the industry [81].
Operating Pressure O_2 Side $P_{stack,O2}$ [bar]	5	5	To maintain low gas fraction on the anode side and favour heat transfer rates [80]
Cell Current Density $I_{cell,max}$ [A/cm^2]	~2	5	3 A/cm^2 as reported in the industry [35] 5 A/cm^2 expected in literature [80] The main constraint is that a higher current densities lower efficiencies occurs; The current density shall results in cell voltages <2.2 V to avoid side reactions, catalyst dissolution & electrode oxidation [80]
Voltage Max Cell Series Connection $V_{max,cells\ in\ series}$ [kV]	<1.5	<1.5	Higher voltage favours shunt/parasitic currents within the system (Expert Opinion).
BOP & PE Power Consumption $Power_{BOP+PE}$ [% $_{Rated\ power}$]	~ 5 - 8	~5 -8	Reported operational experience [35] and Literature [82]. BOP is designed for nominal load. Thus, higher consumption when operating at minimum load and lower when operating a nominal load. No major improvements expected according to [82].
Electrolyzer Power Consumption in hot standby $Power_{Hot\ stand\text{-}by}$ [% $_{Rated\ power}$]	1-5	<5	Reported in literature [83] [82] From product vendors: When the system is set in stand-by circulation pumps are maintained for some minutes to degasify the stack (~5% of power). Then, pumps are switched off and consumption is < 5% of power. Long standby increases energy consumption as recirculation water starts cooling down. Stand-by is usually limited to 1 hr. Afterwards, the system is shut-down and the energy consumed is very low (< 0.25% of power) as it is limited to maintain the safety & control systems.
Concentration of O_2 in the Cathode at nominal load O_2 in H_2 $_{(cath.\ @\ nominal\ Load)}$ [%]	0.1	--	Reported Operational Experience [84] and Expert Opinion. Assuming operation under differentiate pressure, minimal O_2 crossover from anode to cathode.
Concentration of H_2 in Anode at nominal load H_2 in O_2 $_{(Ano.\ @\ nominal\ Load)}$ [%]	0.5	--	Expert opinion. This value is dependant of several variables such as H_2 operating pressure and amount of catalyst recombination present.
Concentration of O_2 in the Cathode at minimum load O_2 in H_2 $_{(cath.\ @\ min,\ load)}$ [%]	0.5	--	Reported Operational Experience [84] + Expert Opinion. Assuming operation under

			differentiate pressure, minimal O_2 crossover from anode to cathode.
H_2 in $O_{2\,Max\,(Ano.\,@\,min.\,Load)}$ [%]	<1.5	<1.5	Maximum allowed H_2 concentration as per safety limits. Higher concentrations trip the alarms and shut down the electrolyzer.
Hot Ramp $rate_{up/down}$ [%/s]	3-10	50	Reported ramp rates at MW scale [85] [86] [87] Upper limit is reported in recent MW scale demonstration project [88]
Hot start-up time [s]	30-40	--	Reported operational experience [36] [85].
Cold start up time [s]	60-300	--	Start-up time is size dependant: due to safety checks, warming & purging time.
H_2-Type A $_{Purity}$ [%]	99.99	99.99	H_2 type I-D standard [89] [90]. H_2O_{max}[v/v%] <5 ppm; $O_{2,max}$[v/v%] < 5 ppm
Turn-down Capacity (Safe Power Operational Range) [% rated power **]	10-100	5-100*	From product vendors: A minimum operating current (and equivalent power) is needed to ensure the safe operation of the electrolyzer. This current is a function of the gas purity on the anode side (H_2 in O_2) to avoid accumulating H_2 beyond the safety limits. In addition, care shall be taken when the electrolyzer is brought to standby mode, as the H_2 crossing from cathode to anode gets recombined in the anode, making it operate in reverse mode. Product vendors recommend depressurizing the PEM stack (the rest of the system can remain pressurized) and flushing the stack with nitrogen if needed (e.g. H_2 built up). Lower turndown capabilities can be obtained by varying the amount of recombination catalyst, membrane thickness, pressure, etc.

BOP= Balance of the Plant; PE: Power Electronics

* Electrolyzers can operate above rated power(degradation accelerates) providing that BOP and PE are designed accordingly. Lower operational limits by e.g. increasing the recombination catalyst, thickening the membrane at expense of efficiency and cost

** Discussions with industry experts indicate that the rated current is typically defined when an operating voltage of ~2 Volts is attained in a cell. Vendors can also specify input current or equivalent power at the point in which unsafe crossover of H_2 occurs.

5.2 PEM Electrolysis Modelling

5.2.1 General Model

A generic electrochemical model was used to estimate the performance of the electrolyzer system. In this model, the operating voltage of an electrolysis cell is a function of the Nernst equilibrium potential (ideal voltage)[28] of the reaction plus the overpotentials[29] of the different components in the cell, as shown in equation (2) below:

$$V_{cell}[V] = V_{rev}^{0}(T, P_{anode}, P_{cathode}) + V_{ohmic}(i) + V_{act,anode}(i,T) + V_{act,cathode}(i,T) \quad (2)$$

Where V_{rev}^{0} corresponds to the Nernst equilibrium potential, V_{ohmic} the ohmic overpotential in the cell, and $V_{act,anode}, and\ V_{act,cathode}$ correspond to activation overpotentials of the anode and cathode, respectively. $T, P_i, P_j\ and\ i$ correspond to the operating conditions of the cell, namely: temperature, anode pressure, cathode pressure and current, respectively.

Whereas the Nernst potential in equation (2) is only a function of the operating conditions of the cell, the overpotential depends on the characteristics of the cell (such as membrane thickness, catalyst loading, and catalyst type). Therefore, the model needs to be parametrized—for this aim, PEM electrolysis parameters from experimental studies available in the literature [91, 92, 93] and internally provided by TNO were used.

From equation (2) the voltage output at different operating currents can be determined. The production and consumption the component in the electrochemical reaction was determined by using the Faradaic constant through the following relation.

$$r_j\left[\frac{mol}{m^2 s}\right] = \frac{1}{A_e v_i}\frac{dn_i}{d_t}\ ;\ n_j[mol] = \frac{A_e it}{F} \rightarrow\ r_i\left[\frac{mol}{s}\right] = \frac{i}{v_i\ F} \quad (3)$$

Where r_i is the molar production rate of a component j (in this case hydrogen), A_e is the electrode surface area in $[m^2]$, t is the time in $[s]$, i is the current density in $[A/m^2]$, v_i $[-]$ is the stoichiometric coefficient of the component j, and F is the faradaic constant in $\left[\frac{As}{mol}\right]$.

Further description of the model, specific parameters and reference performance curves used for model validation can be found in Appendix C.3.

5.2.2 Performance curves

Figure 17 (left) depicts the resulting IV (current-voltage) performance curves at different input currents for an electrolyzer cell[30] using the previously discussed electrochemical model and the operating conditions and characteristics shown in Table 17.

As shown in the Figure 17 two primary states of the electrolyzer are identified: the beginning of life (BOL) and at the end of life (EOL). The differences between the two states are the result of the electrolyzer

[28] The Nernst potential basically indicates what is thermodynamically required to drive the reaction
[29] In electrochemistry overpotential refers to energy losses or resistances in the cell
[30] The stack's performance (e.g. voltage) is determined by the number of cells in the stack.

degradation over time. From discussions with TNO experts, the electrolyzer's EOL is set to the state where an increase in 10 % of the rated voltage is attained.

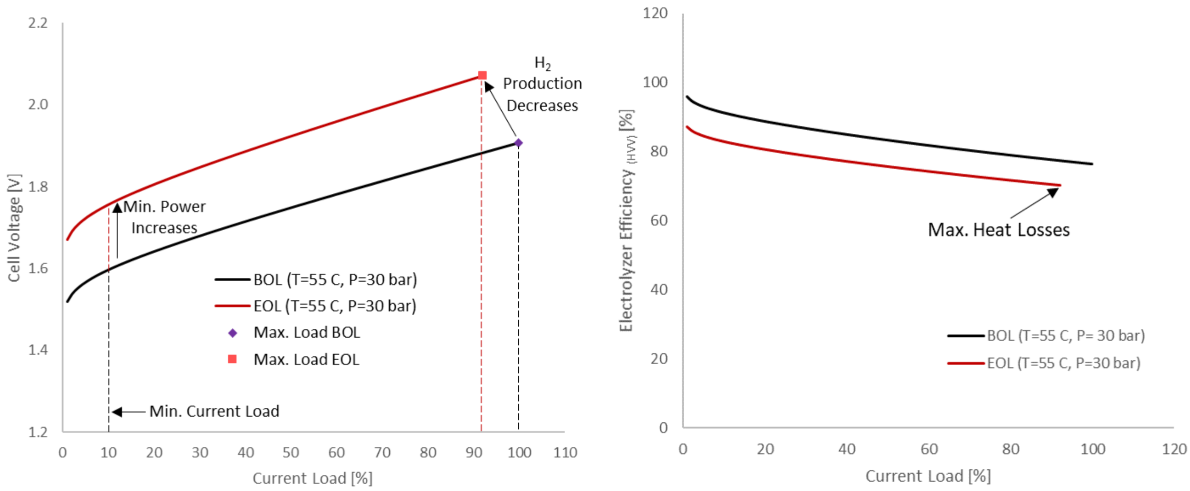


Figure 17 I-V (left) Electrolyzer Performance Curve at the beginning of Life (BOL) & end of life (EOL); (right) Electrolyzer Efficiency (ref. H_2 High Heating Value) at the beginning of Life (BOL) & end of life (EOL)

In Figure 17 (left), a black dotted line at ~ 10 % rated current load indicates the operating threshold defined for the electrolyzer. As mentioned in Table 17, a minimum operating current in the electrolyzer system is required to limit the built-up of hydrogen crossing over from the cathode to anode (and thus avoid H_2 in O_2 concentrations above the safety limits). As shown in the figure, for a predefined minimum current, the power input (from P = Vx I) increases at EOL compared to the BOP:(as a higher voltage is required). Under the assumed voltage increase at the electrolyzer's end of life, the increase in power is relatively modest from around 9 % rated power at BOL to 10 % rated power at the EOL[31]. For the design, the minimum power threshold of 10 % rated power is used as a safety constraint. This power threshold aligns with the ones reported in the industry (see Table 17).

Note that at the EOL, the maximum current load decreases as the total power input is maintained. Therefore, as current load and hydrogen production are proportional (see equation (3)), the electrolyzer produce less hydrogen towards the system's end of life[32].

Figure 17 (right) depicts the electrolyzer's energy efficiency (based on H_2 high heating value) as a function of the current load. This figure shows that operating below rated power results in an increase in the efficiency of the electrolysis process; however, as mentioned before, it also implies that less hydrogen is being produced. Electrolyser vendors generally define rated power when the maximum balance between energy efficiency, stack degradation and hydrogen production is obtained. Therefore, operation at rated power is the preferred option.

In addition, Figure 19 (right) shows that as the system degrades with time, the performance curve will shift towards lower efficiencies at the end of the system's life. Lower efficiencies imply that more heat losses need to be handled. Therefore, energy losses at the end of life are used for the design of cooling equipment.

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[31] Assuming 8 % rated power consumption for balance of plant & power electronics at minimum load (see Table 17)

[32] Note that state of art electrolyzer currently have a lifespan between 60000 and 80000 full load operating hrs.

It is important to clarify that besides the electrolyzer stack (s), the balance of plant (BOP) and the power electronics (PE) also consume energy. This extra energy consumption is also a function of the system load and the operating strategy used. Therefore, as a basis of design, the efficiency figures shown in Table 17 are used. However, a reference of the auxiliaries performance at different loads reported by product vendors is shown in Figure 10 in the appendix.

5.3 Site Wind Characteristics

To determine the wind characteristics at which the system will be exposed, measurements data from the offshore meteorological platform Ijmuiden were used as a reference. The measurement platform is located 85 km from the Ijmuiden coast of the North Sea, and therefore the following analysis applies for that area (as climatic conditions vary at different locations). In addition, to cover seasonal and yearly variations, data from multiple years are used. In this case, the data points correspond to the recordings from measurement campaigns performed between 2012-2016.

The wind data was received as raw 4 Hz resolution data measurements recorded by cup anemometers located at 27m, 58m, 85m and 92m above the lowest astronomical tide (LAT). A processing script was written to treat the data and extract some of the main features of this location. The results of this treatment are described as follows.

5.3.1 Wind Distribution

In order to estimate the wind variation throughout the rotor, the wind data point measurements at different heights were fitted to a power-law function. The power-law exponent (α) resulting from the regression (~ 0.099) is in the range of previous results obtained within TNO [94][33]. Next, the rotor-effective wind speeds[34] were calculated to estimate the effect of the wind speed variations on the aerodynamic power captured by the rotor.

Figure 18 (left) depicts a histogram of the estimated wind speed distribution at the assessed site, for which a Weibull-probabilistic distribution function (PFD) was fitted. For this fit, the data was first converted into 10-minutes averaged wind speed data. The scale (A) and shape (K) Weibull parameters obtained for the fitted distribution are included in the figure. The following sections use the fitted distribution to determine the turbine's expected power production and estimate the annualized power production during the economic assessment.

The rotor-effective wind speed is an approach to take into account wind speed variations over the rotor sweep area to provide more accurate power curves for large wind turbines when compared to wind speeds at hub height

[33] In this report a warn is made that power law function overestimates the wind speed at higher altitudes when compared with real data obtained with LIDAR technology. Therefore, more precise data could be used in future stages of design.

[34] The rotor-effective wind speed is an approach to take into account the effect of wind speed variations over the rotor sweep area to provide more accurate power curves for large wind turbines when compared to wind speeds at hub height. The procedure can be found in the IEC 61400-12-1. Ed 2.

Figure 18 (right) shows the turbulence intensity (TI) as a function of the wind speed, which represents all wind speed variations within a 10-minute interval. The figure shows that turbulence intensities below 10% are expected for most of the operating wind speeds for the site's specific characteristics.

The TI results are used in the coming section for the dynamic (operational) analysis, which asses the matching characteristics of the electrolyzer system and the wind turbine.

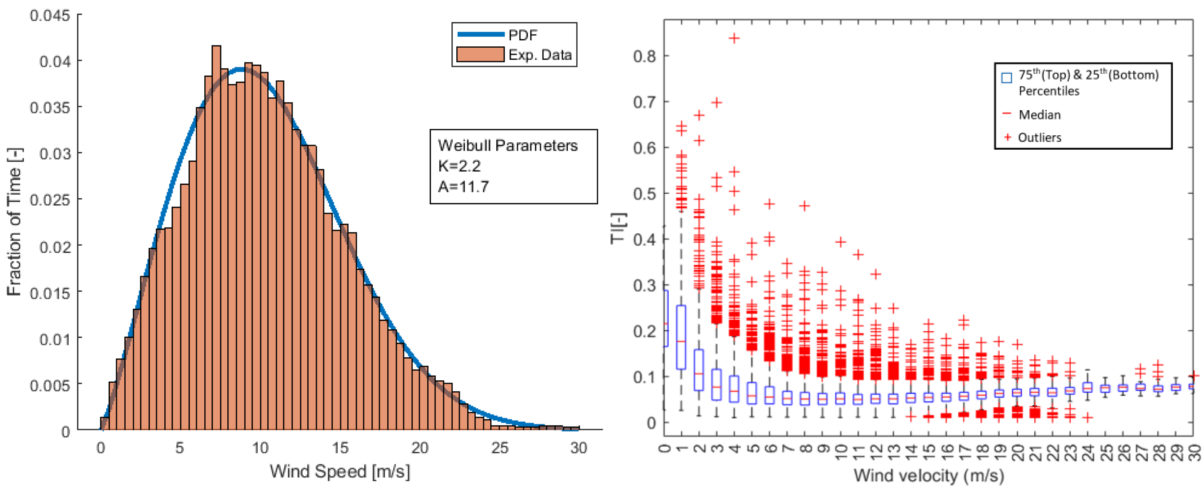

Figure 18 Estimated (left) Rotor Effective Wind Speed & PDF function, (right) Turbulence Intensity distribution at Ijmuiden

5.3.2 Power Production distribution

For the system design, it is necessary to define the capacity of the electrolyzer system[35] compared to the rated power of the reference wind turbine. In general, under-sizing the electrolyzer system is not considered an option for this specific system, as the turbine is not connected to the grid, and therefore, the excess of power produced by the turbine would need to be wasted (also known as energy curtailment).

On the other hand, oversizing the electrolyzer system could provide some benefits in terms of efficiency and increase of lifespan of the electrolyzer system (which can potentially reduce the number of replacements performed offshore). However, it comes at the cost of operating the electrolyzer system with lower capacity factors. At this design phase, the impact level of these variables on the final hydrogen cost is still unknown; therefore, as a starting point for the design, it is assumed that the electrolyzer system has the same rated capacity as the wind turbine (15 MW).

To gain insight into the turbine's power production distribution and how it reflects on the electrolyzer system, the power distribution of the reference turbine is analysed. Figure 19 depicts the fraction of time in which the turbine operates at a particular power level (using power bins of 0.5 MW). In this figure, a red dotted line is added to represent the minimum threshold power requirement of the electrolyzer system (taken as 10% of a single 15 MW PEM System = 1.5 MW). This figure was made using the fitted Weibull

[35] Electrolyzer system composed of stack+ Balance of the plant (BOP) are estimated to consume around 5% of the energy at rated power.

distribution (see Figure 18) in combination with the performance characteristics of the turbine (See Table 9 in section 4.3.2)

As shown in Figure 19, around 16 % of the time, the wind turbine does not produce sufficient power to supply a single electrolyzer system rated at the same capacity than the turbine generator. This scenario occurs either because the wind speed is outside the operating limits of the turbine (cut-in & cut off wind speed) or the generated power is insufficient to ensure the safe operation of the electrolyzer system.

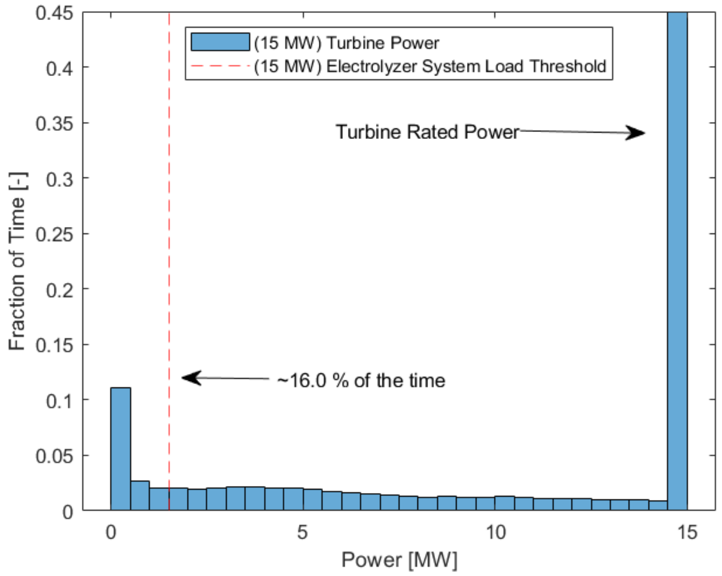

Figure 19 Turbine Power Production Distribution. Power Bins of 0.5 MW

A further division of the distribution in time of the operating scenarios is shown in Figure 20. From this figure, around 6 % of the time corresponds to the "no power generation" scenario, resulting from the wind speeds outside the operating ones of the turbine. On the other hand, 10 % of the time, the turbine operates but does not produce power to fulfil the minimum electrolyser power requirements (~10 % of electrolyze's rated power), leading to unsafe operational scenarios.

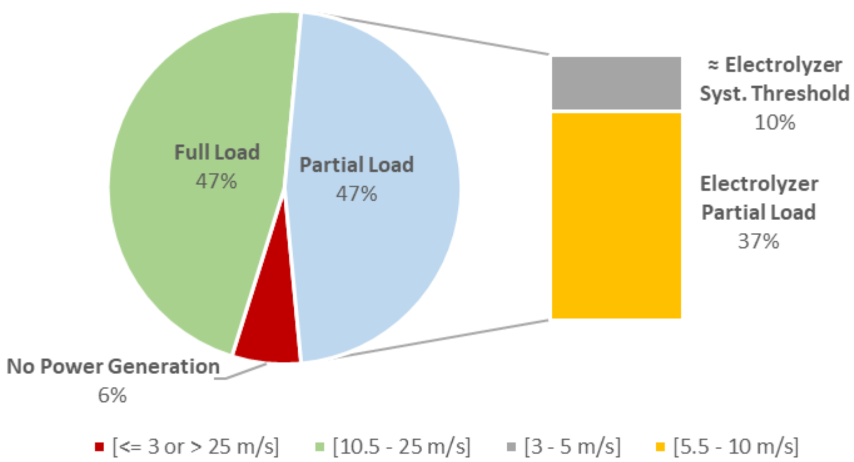

Figure 20 Wind Turbine Electrolyzer System Operating Mode Distribution in time

Note that the electrolyzer threshold used assumes a ~15 MW electrolyzer operating as a single system. In reality, electrolyzer systems can take a modular approach, from which a system is composed of several modules (or stacks) that can be operated independently. Having multiple stacks, in this case, is beneficial because the system can shut down (or put in hot standby) some electrolyzers modules to reduce the minimum load required for safe operation. Also, power dispatching strategies can be applied to optimize the efficiency and lifetime of the stack modules under variable input power and other operating conditions.

From the performance curve of the IEA 15 MW reference turbine it is observed that at the turbine's cut it wind speed the power production is slightly above 0.5 MW. Therefore, to match with the minimum safety constraint the electrolyzer system would ideally be divided into three 5 MW modules (as 10% is 5 MW is 0.5 MW). This minimum level of modularization, combined with additional operating requirements, are further assessed in the following section.

5.4 Flexibility & Operation

Wind power fluctuates by nature; the power production at an individual wind turbine usually shows a significant output fluctuation[36] [95]. This fluctuation results from the combined effects of several variables, such as wind speed fluctuations, turbine control algorithm, tower shadow effect, turbine inertia, among others [96, 97].

As the system design requires the integration of electrolysers with individual wind turbines, it is crucial to verify whether the dynamics (here, the power production and consumption in the time domain) of these systems match to perform a safe operation and maintain the system's integrity. The approach taken for this verification was to simulate the power production for the reference turbine at three different operating scenarios: partial load-low power, partial load-below rated power, and full load-above rated power and analyse the results in terms of the operational capabilities of the electrolyser system.

The turbine dynamics are simulated in the OpenFast tool, with the publicly model data for the 15 MW offshore reference turbine [58, 98]. This tool couples aerodynamic, hydrodynamic, servo and elastic models to simulate the response of a wind turbine in the time domain. The tool uses metOcean conditions (e.g. wind inflow, wave, current characteristics), control logic and turbine characteristics for the simulation. In this case, the version of the 15 MW reference wind turbine used is the monopile model, and metOcean characteristics at Ijmuiden site and for a IEC wind class IB[37] are used.

To explore the impact of having modules instead of a single electrolyzer system. In the analysis, based on the expected cut in power of the wind turbine(slightly above 0.5 MW), the electrolyzer system is assumed to be comprised of three individual modules , each of 5 MW[38] rated capacity. Each electrolyzer module is assumed to have a minimum load threshold of 10 %; below this threshold, the module can be taken offline or set in standby mode.

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[36] At a wind farm level, power fluctuations are less pronounced than in an individual turbine
[37] Wind speed, extreme gust and turbulence that a turbine may face an must withstand throughout its lifetime
[38] Current industrial electrolyzer stacks have a power rating of up to 2.5 MW, whereas future developments aim to increase the power rating up to 5 MW.

To run the simulations in OpenFast, wind time series with a characteristic turbulence intensity (TI) were generated using a stochastic turbulence simulator (Turbsim [99]). The simulator requires as input the characteristic TI for the site to model. These TI were obtained from the wind measurements' statistical analysis performed in the previous section (see Figure 18).

In addition, as wind speed variations are specific to the site, time-series with TI for an IEC class IB turbine are also used. The IEC class IB time series represents the operating scenario for which the reference turbine was initially designed (see Table 9).

5.4.1 Results for Partial Load-Low Power Operation

Figure 21 depicts the generated wind speed time series for 10 min time steps. The 10 min averages of the wind time series are 4 m/s (left) and 5 m/s (right), with turbulence intensities of 8 % and 7%, respectively. In this figure, the relatively low TI results in relatively smooth wind speed time series.

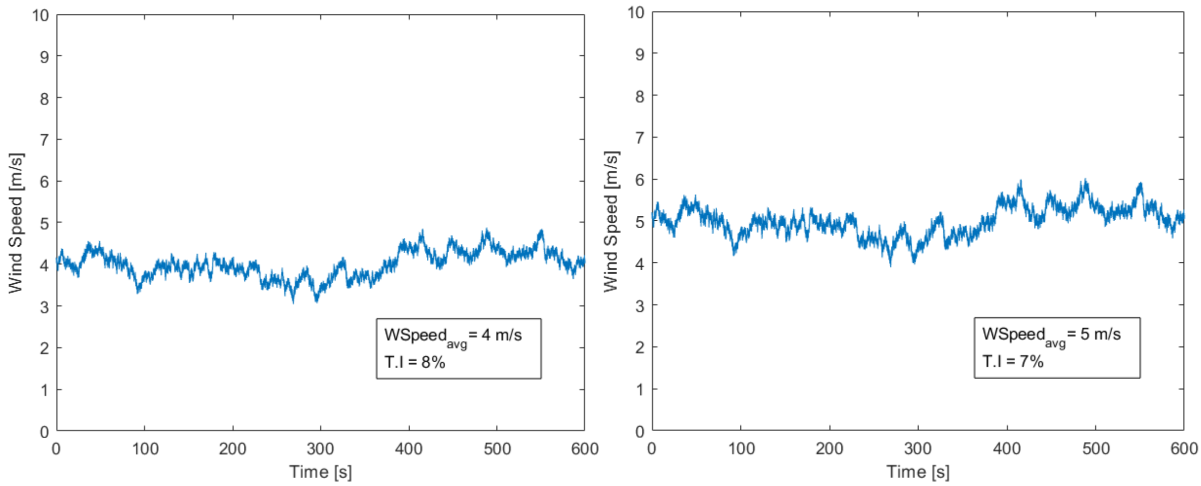

Figure 21 Generated (left) 4 m/s and (right) 5 m/s Wind Speed time series

The previous time series are used as input in OpenFast to simulate the dynamic power response of the reference turbine. The resulting power outputs are depicted in Figure 22 and Figure 23. In these figures, the zones indicating the limit in which one or two modules would need to operate in hot standby mode are defined by red lines. The red coloured area corresponds to the zone where the whole electrolyzer system needs (the three modules) would need to operate either in hot standby or shut-down, as not enough power is available from the wind turbine.

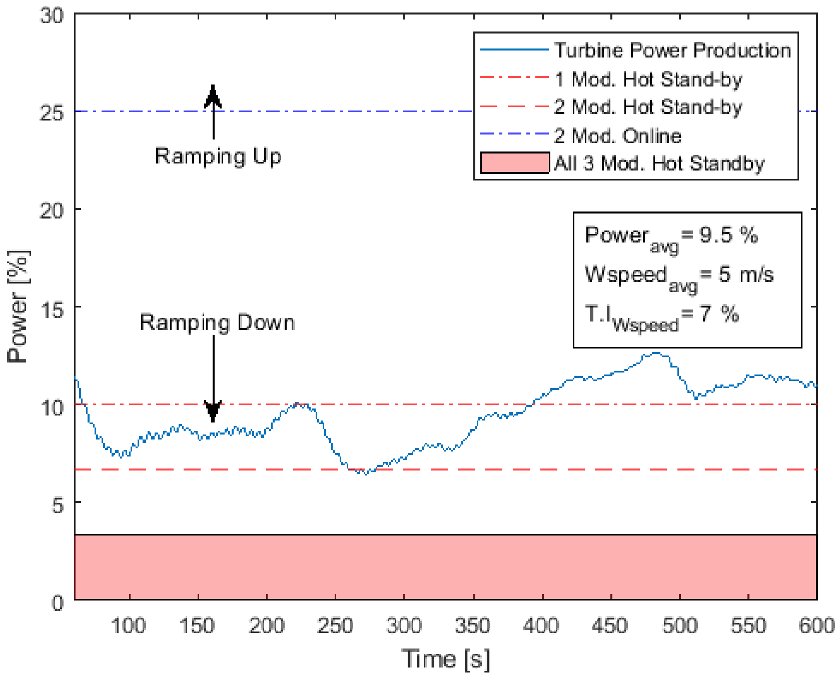

Figure 22 Power Production for a 5 m/s average wind speed, TI = 7%

Figure 22 shows that although the wind variations are relatively smooth at low wind speeds, the fluctuations in power production would make the electrolyzer operate below the safety thresholds (red lines). Therefore, to address this problem, a control strategy could utilise the system's modularity to extend the minimum operating threshold in this scenario. For example, in a ramping down scenario (the power production is continuously decreasing), the control system can set a module in hot standby when approaching its respective safety limits. However, as shown in the figure, the turbine's power fluctuations continuously cross the operating limit where it is needed to set one or more modules in stand-by (intersection of power curve with red lines in the figure). In this regard, product vendors indicate that continuous switching on/off of a PEM module is not recommended as it can potentially accelerate degradation. Therefore, to prevent frequent start/stop of a module, the control strategy can set a minimum power production(e.g. blue dotted line in the figure) before it is set back in operation.

Figure 23 shows that close to the cut-in wind speed of the turbine (3 m/s), there are already moments in which the produced power falls below the minimum threshold for all the modules (corresponding to the intersection between the red coloured area and the turbine power production curve). Therefore, to avoid operation below the safety constraint, additional measurements need to be taken. As indicated in Figure 23, the power gaps of energy are characterized for being of relatively short duration (100 s), which falls between the operation range of storage technologies such as supercapacitors (see Figure 47 in Appendix C.2). Therefore, the use of supercapacitors technology is recommended to a temporary buffer and smooth the power fluctuations of the turbine. Note that this technology is preferred over batteries as supercapacitors have larger power densities and a much longer lifespan (critical in offshore environment).

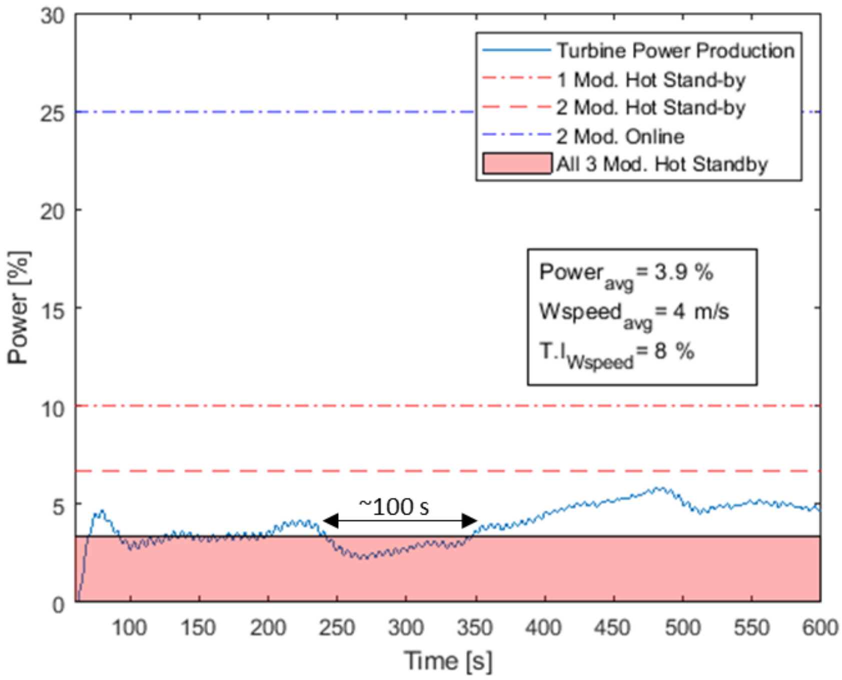

Figure 23 Power Production for a 4 m/s average wind speed, and Turbulence Intensity (TI) = 8%

Additional measures that can be taken to avoid operation below the minimum threshold include shifting the turbine's cut-in wind speed or setting the electrolyzer in standby mode at higher wind speeds. In these scenarios, the turbine would have to waste part of the energy, but the system's safety is preserved. Alternatively, further modularization of the electrolyzer could be considered. However, the three 5 MW modules combined with the supercapacitor seem to be sufficient to circumvent the power gaps at very low wind speeds, and therefore are maintained for the design.

Note that the electrolyzer (module or system) consumes some power during standby mode (< 5% rated power) and to ensure that safety and control systems remain operative (< 0.25 % rated power). Therefore, for the scenario in which an operating turbine operate at low power production, the control strategy needs to be adjusted to ensure the mentioned power is provided. On the other hand, for the scenario in which the turbine does not produce power or the integrated electrolyzer-turbine system has a cold start, a backup system (which also needs to consider the turbine's safety and control systems) is required. The sizing of the backup system could be explored in the future design stages when more insight into the energy requirements for a cold start of a wind turbine is gathered. Finally, in the extreme case of a sudden power outage, product vendors indicate that thanks to PEM electrolysers' differential pressure capabilities, these systems can be (and have already been) designed to shut down safely. The elements mentioned above are undoubtedly critical and need further revision in future design stages. However, they are not seen as a showstopper at this design stage as robust systems can be engineered over it.

5.4.2 Results Partial Load Operation: Below-Rated Wind Speed

Turbine simulations at partial load operation and below rated wind speed were performed to verify whether the ramping electrolyzer rates match the variations on power production. The ramping capabilities of PEM electrolysis systems at an industrial scale (> 1 MW) are currently reported by product vendors to be around 10 % rated power/second. Therefore, these rating capabilities are assumed for the discussion below.

For the analysis, 10 m/s average wind speeds time series with turbulence intensities of 6.7% (for Ijmuiden site) and 18% (IEC class B) were generated. Figure 24 shows the resulting power series and the maximum ramping rates for the studied cases. In this figure, the reference site generated conditions (Ijmuiden) resulted in ramping rates (~1.5 % rated power/second) in the range at which the electrolyzer can perform. On the other hand, the higher turbulence intensity for the IEC class B profile results in more pronounced step changes of around 9.7% rated power/second, which tightly comply with the current electrolyzer ramping capabilities. In this case, similar to the previous scenario, using a supercapacitor can help smooth the power fluctuations received by the electrolyzer system.

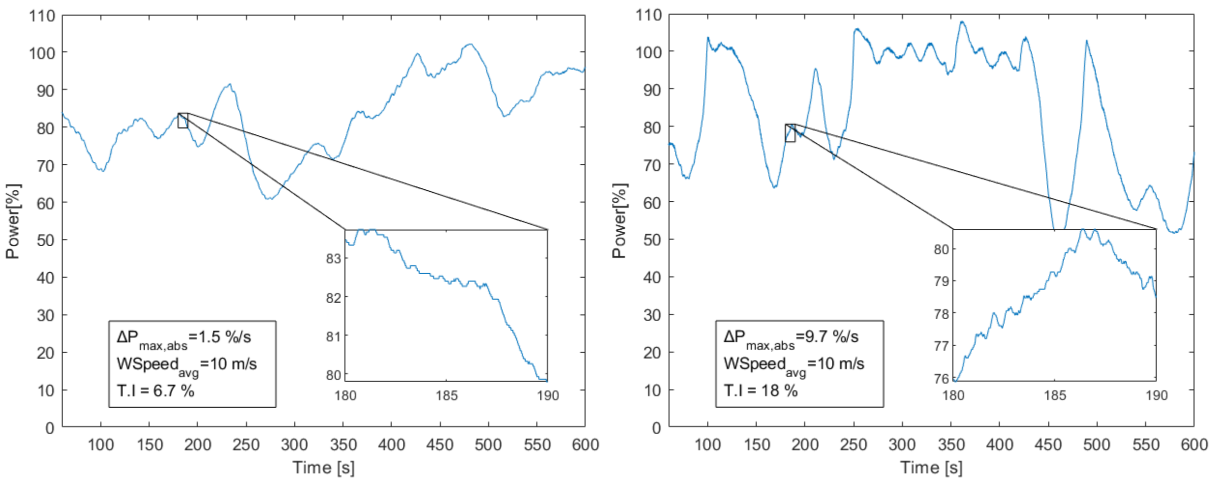

Figure 24 Maximum Absolute Step Changes ($\Delta P_{max,abs}$) at partial load. For (left) Ijmuiden, (right) IEC class B profiles

5.4.3 Results Rated Power Operation

The last operational scenario analysed corresponds to the turbine operating at rated power. In this scenario, the turbine control limits the production power by varying the pitch angle of the blades. For this case, the turbine simulations were performed using wind speed time series at 15 m/s with turbulence intensities of 6.1% (Ijmuiden) and 18 % (IEC class B), available in the appendix.

Figure 25 shows the resulting power time series for the turbine operating at rated power. For both cases, the turbine control smooths the power changes and maintains them below 2.5 %/s. Therefore, this operational scenario is compatible with the current capabilities of industrial electrolyzers.

In addition, Figure 25 also shows that the generated power fluctuates around the rated power, from which peak powers of +103 % (Ijmuiden) & 109 % (IEC Class B) of the rated capacity are found. However, these relatively short power peaks are not expected to be a problem as PEM electrolyzer systems are capable of operating above rated power (providing that balance of the plant and power electronics are sized accordingly). Alternatively, the control system in the turbine could also be set to release the excess power into a dump load[39] to avoid overloading the electrolyser system.

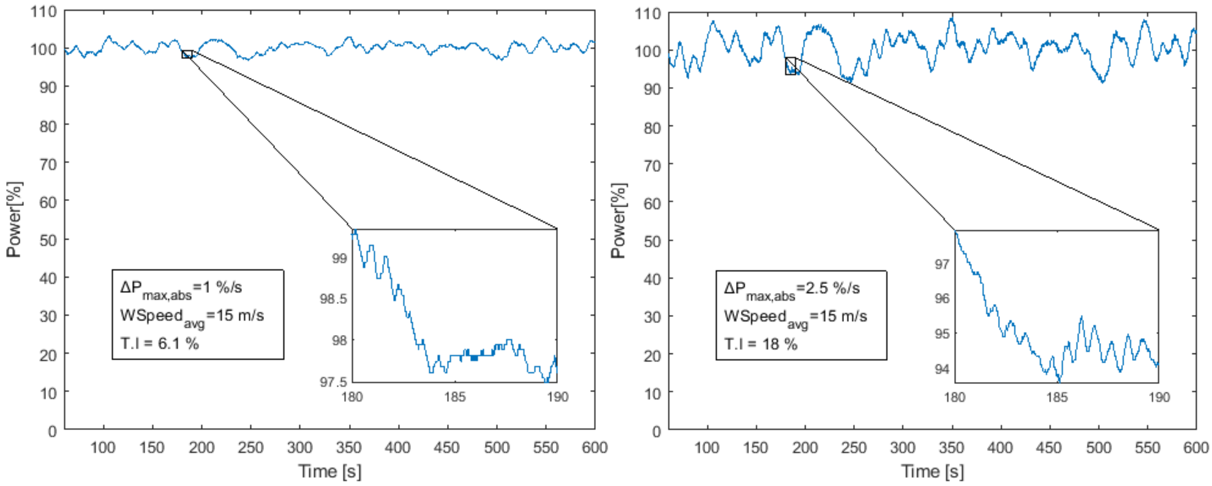

Figure 25 Full Load Operation-Power Time Series. $\Delta P_{max,abs}$= Maximum Absolute Step Change

The previous analysis demonstrates that at the scale of the 15 MW turbine, the power fluctuations below and rated power are inside the electrolyser system's fluctuation range. Therefore, no showstoppers are identified at this design stage in terms of flexibility.

[39] Usually an electric heating element to which the excess power can flow

5.5 Space Footprint & Weight

Previous desk studies [7] suggested integrating the electrolyzer modules inside the wind turbine tower, which appeared to be straightforward when considering their relative dimensions. For example, as illustrated in figure 28, a 10 MW offshore wind turbine tower has a bottom diameter of ~8 m (which would result in a 50 m^2 area). In contrast, a 2 MW PEM electrolyzer module[40][41] occupies a footprint area of ~ 3 m^2. Therefore, five 2 PEM modules (to match the turbine capacity) can be easily arranged to fit inside the turbine base.

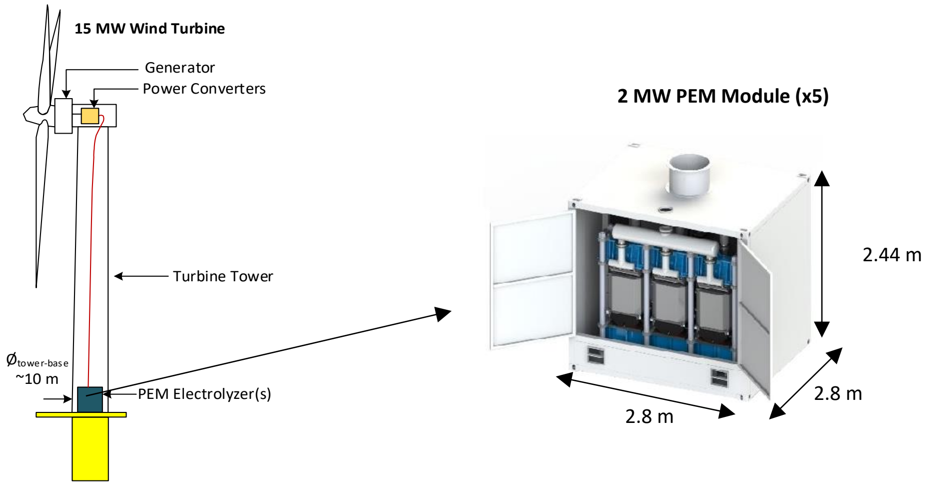

Figure 26 Installation of PEM Electrolyzer at the Bottom of a Wind Turbine.2 MW PEM Module reproduced from [35]

This integration, however, considers only the electrolyzer module. As shown in the preliminary analysis (see section 4.3.3), besides the module, an electrolysis system requires numerous equipment (such as separators, heat exchangers, dryers, among others) to ensure hydrogen production. Thus, when the additional equipment is considered, the total footprint of the electrolysis system increases dramatically.

The footprint of an electrolysis system varies widely depending on the manufacturers and specific projects where PEM electrolysis plant footprints ranging from 19 to 48 m^2/MW can be found. As an illustration, Figure 26 shows a physical view of the 10 MW PEM electrolysis system concept (where five adjacent 2 MW PEM modules are fitted in a containerized skid) showcased by ITM [35]. As can be seen in the figure, some units, such as the plant cooling, phase separator, and power converters, have a significant contribution to the total footprint of the plant. However, note that these concepts were initially designed for onshore applications with less stringent space limitations than when integration on offshore wind turbines is pursued. Therefore, a closer look at whether this equipment can be adapted to minimize its footprint is performed in the following sections.

[40] As mentioned before, stacks are typically arranged in modules, and larger capacities are obtained by upnumbering

[41] Estimated size from 2 MW standard modules showcased by ITM.

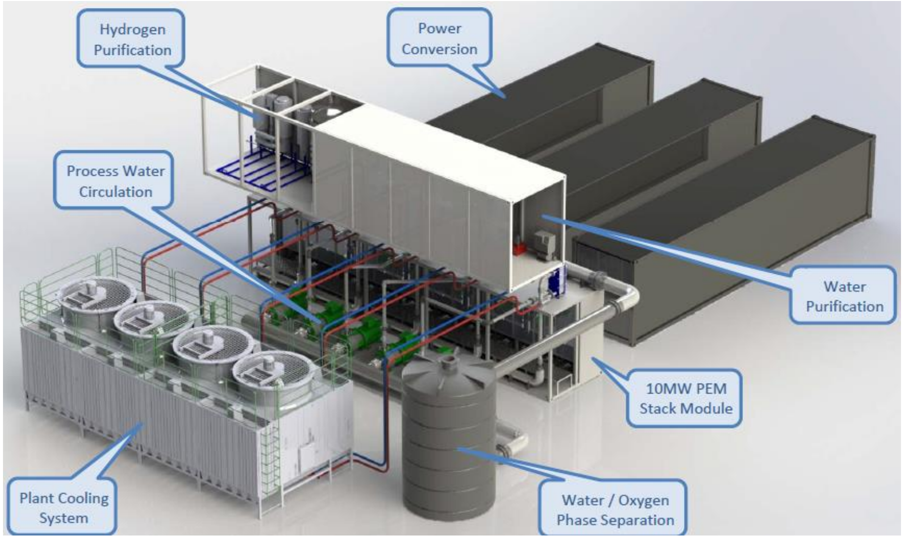

Figure 27 ITM 10 MW Electrolyzer Concept. Reproduced from [35]

5.5.1 Process Mass Balance

Process mass balances were performed for the electrolysis system to identify flows of material within the system. The results of these mass balances are used in the following sections to estimate the size of different process equipment. The balances are performed for the main components in the electrolysis system assuming perfect mixing, no accumulation of mass over time, equilibrium for the separators and stoichiometry calculations for the electrolysis and de-oxo reactions. To calculate the mass balance, the models introduced in section 5.2 and the technical parameters shown in Table 17 were used. The required mass flow of process water for cooling was determined based on an adiabatic model to maintain the temperature difference in the electrolysis below the set limit ($\Delta T_{stack,max} < 10$ C).

Note that the mass flows differ between the electrolyzer beginning of life and end of life due to stack degradation. Therefore, the mass balances were performed for the mentioned two states. The resulting material balances are summarized in Table 36 and Table 37 in the Appendix C.5. In addition, to illustrate the scale of system's material flows a simplified version of the material balances are shown in Table 16 below. This table is accompanied by Figure 28, in which the flow streams are enumerated to facilitate the understanding.

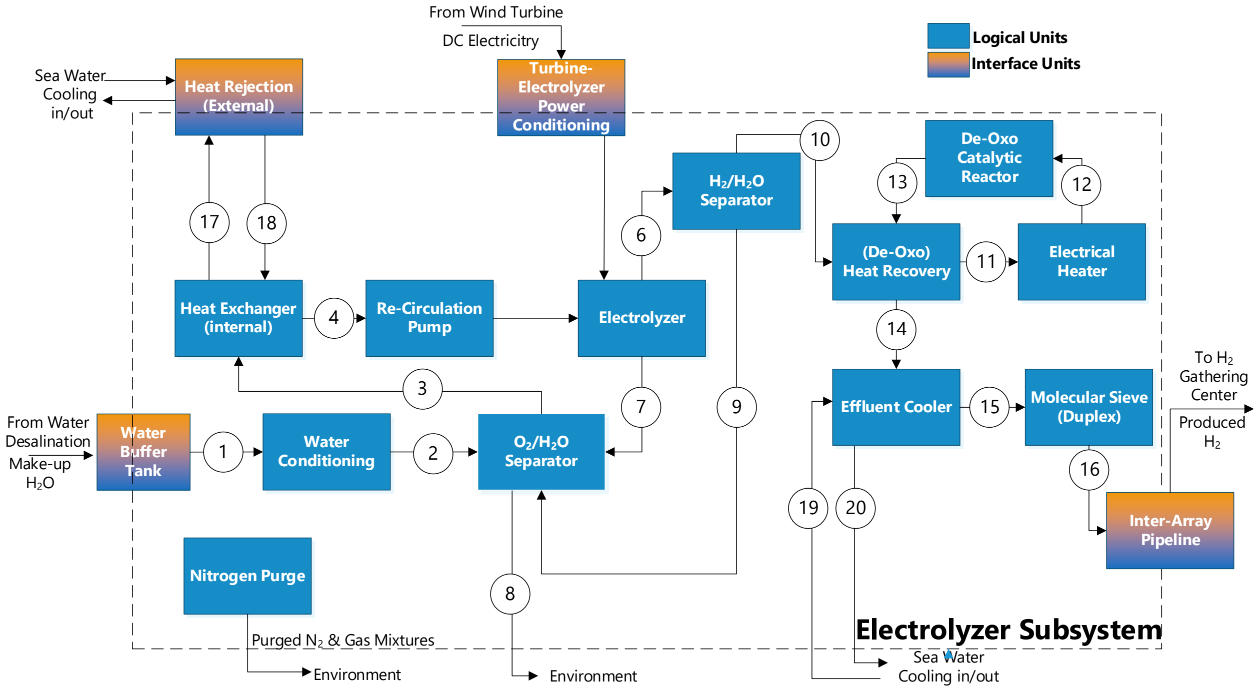

Figure 28 Process Flow Diagram (PFD) Electrolysis System

Table 18 Electrolyzer Module (5MW) Mass Balance @ BOL (Simplified)

5 MW Module @ BOL - Operation Mode: Full Load					
Stream Name	**D. H_2O Supply**	**Conditioned H_2O**	**H_2O Recycle**	**Cooled H_2O**	**Electrolysis H_2O**
Stream	**1**	**2**	**3**	**4**	**5**
T [C]	25	55	60	55	55
P [Bar]	3	3	3	3	5
m_{total} [Kg/h]	823	823	185908	185908	185908
m_{H2} [Kg/h]	0	0	0	0	0
m_{O2} [Kg/h]	0	0	0	0	0
m_{H2O} [Kg/h]	823	823	185908	185908	185908

Stream Name	**Cathode Side**	**Anode Side**	**O_2 exhaust**	**Cathode H_2O Recycle**	**H_2 Gas Mixture**
Stream	**6**	**7**	**8**	**9**	**10**
T [C]	55	55	60	60	60
P [Bar]	5	5	3	30	30
m_{total} [Kg/h]	4796	181112	727	4702	94
m_{H2} [Kg/h]	87	0	0	0.19	87
m_{O2} [Kg/h]	1.4	696	693	0	1
m_{H2O} [Kg/h]	4707	180417	34	4702	5

Stream Name	**Pre-heated H_2 Gas Mixture**	**Heated H_2 Gas Mixture**	**O_2 Free- H_2 Wet Gas**	**Pre-Cooled H_2 Wet Gas**	**Cooled H_2 Wet Gas**
Stream	**11**	**12**	**13**	**14**	**15**
T [C]	140	200	218	140	25
P [Bar]	30	30	30	30	30
m_{total} [Kg/h]	94	93	93	93	93
m_{H2} [Kg/h]	44	44	44	44	44
m_{O2} [Kg/h]	0	0	0	0	0
m_{H2O} [Kg/h]	0	0	0	0	0

Stream Name	Dried H_2	External HX Coolant In	External HX Coolant Out	Effluent Coolant In	Effluent Coolant Out
Stream	**16**	**17**	**18**	**19**	**20**
T [C]	25	15	40	15	25
P [Bar]	30	1.1	1	1.1	1
m_{total} [Kg/h]	87	111545	111545	3860	3860
m_{H2} [Kg/h]	43	6197	6197	207	207
m_{O2} [Kg/h]	0	1	1	1	1
m_{H2O} [Kg/h]	0	0	0	0	0

5.5.2 Energy Distribution

The electrochemical model introduced in section 5.2 is used to determine the efficiency of the electrolysis process. From this calculation, it is possible to estimate the heat generated in the system. In addition, the balance of the plant energy requirements & power losses were included as per the assumptions shown in Table 17.

Like the mass balance, the energy flows are a function of the life state of the electrolysis system. In particular, the higher heat generation occurs towards the electrolyzer end of life (EOL), in which an increase of 10% of the operating voltage was assumed. The results of this calculation are summarized in Table 19. Note that for this case, energy flows are shown per module and for the system. The reason for showing the system energy flows is that the total heat produced by the system is the one that needs to be handle by the external heat exchanger for final transfer into the environment.

Table 19 Electrolysis System Energy Balance

	Electrolyser BOL		**Electrolyzer EOL (+10% V)**	
Parameter	**5W Module**	**15 MW System**	**5MW Module**	**15 MW System**
Power to Electrolyzer System [MW]	5.0	15.0	5.0	15.0
Energy Content* Produced H_2 [MW]	3.4	10.3	3.2	9.5
Heat Generated [MW]	1.2	3.5	1.4	4.3
BOP & PE Consumed Power [MW]	0.4	1.2	0.4	1.2
Voltage** [KV]	0.67	0.67	0.72	0.72
Current** [KA]	6.9	20.7	6.4	19.1
*HHV as reference;** at the electrolyzer's only the rest of the power is supplied to BOP or consumed by PE				

SYSTEM VIEW-Energy Consumption

When looking at the system in a wind farm context, the produced electricity must also power the desalination and compression processes. To understand what these energy flows represent, estimates of energy requirements for these processes are calculated. Figure 29 depicts the energy distribution among the system. In this figure, the energy usage for desalination and compression is relatively low compared to the energy lost as heat or used at the BOP & PE processes.

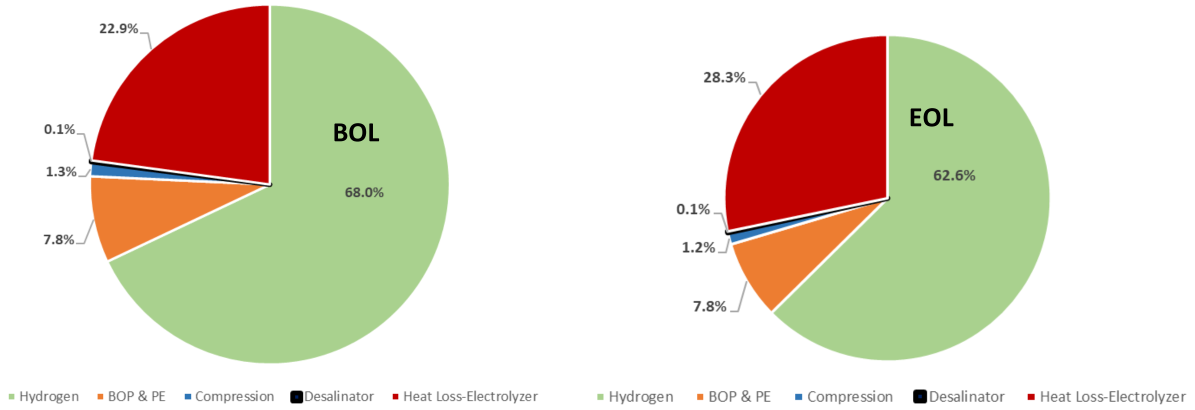

Figure 29 System Energy Distribution at BOL (Left) & EOL (Right). Assumed H_2 compression pressure up to 100 bar

These figures assume centralized compression from ~29 bar (from the PEM electrolyzer) to 100 bar (for transmission). Therefore, the higher the transmission pressures, the higher the energy used for compression. For example, increasing the transmission pressure from 100 bar to 400 bar (current limit of dry reciprocating compressors) increases the energy requirements from 1.3 % to ~3.2% at the BOL(see Figure 49 in Appendix C.4)

5.5.3 System Footprint

To understand the space requirements of the equipment needed to produce hydrogen, equipment sizes were estimated by applying equipment design principles and/or consulting manufacturers of specific packages. The footprint estimation was performed only for the main equipment, as detailed sizing is out of the scope of this PDEng project. Figure 30 shows a simplified view of the main systems considered for the footprint estimation.

As shown in Figure 30, for the footprint estimation the electrolysis system was organized into electrolysis and purification modules. This modularization is commonly used in the PEM market and helped perform assumptions when there was a lack of information.

The electrolyzer modules include mainly the PEM stacks, O_2 & H_2 separators and internal heat exchangers. These modules are assumed to have each 5 MW capacity (see section 5.4), and thus three of them are required to form a 15 MW system. Note that this decision implies that potential benefits of footprint reduction by additional scaling up of equipment such as gas/liquid separators and heat exchangers were restricted to the rated capacity of each 5 MW module. The reasoning behind this decision was to maintain a minimum level of flexibility and interdependency among the modules.

On the other hand, the purification module includes water conditioning, de oxo reactors, and dryers. In this case, it is assumed that a single purification module handles the flow of required water and produced hydrogen in the system. Furthermore, these modules are assumed to be fitted in containerized skids to facilitate transport & installation and protect the equipment from the harsh offshore environment.

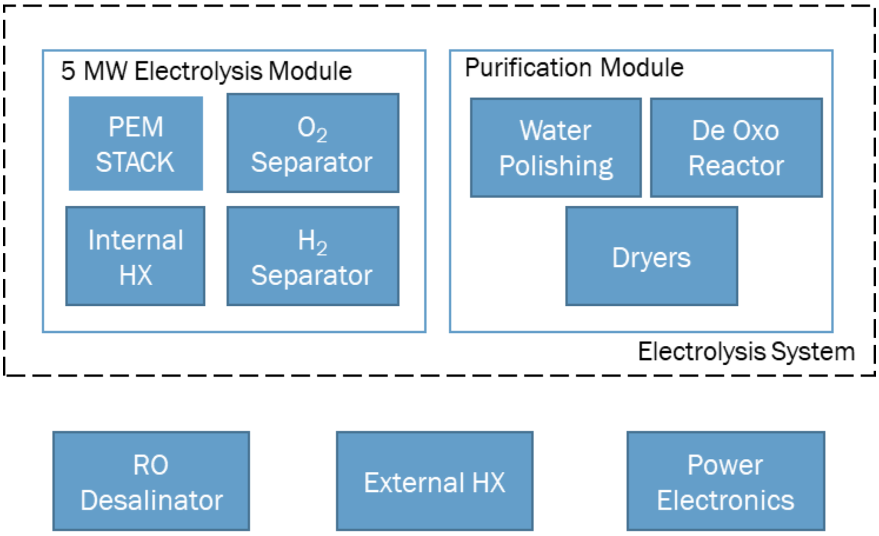

Figure 30 Module Distribution for Footprint Estimation

The results of the footprint estimations are summarized in Table 20 and further described afterwards.

Table 20 Systems Footprint Estimations & Equipment Characteristics

Module	Components	No units [-]	Estimated min. Footprint (LxWxH [m])
(3x*) 5 MW Electrolysis Modules (LxWxH [m]) (9.1x2.4x2.6)**	Electrolysis Stack	6 (2 per module)	0.8x0.55x1.65
	O_2 Separator (Horizontal)	3 (1 per module)	$L_{Horizontal}$=4.9 m Ø= 1 m
	H_2 Separator (Vertical)	3 (1 per module)	$L_{Vertical}$=0.9 m Ø= 0.35 m
	Internal Plate Heat Exchanger	3 (1 per module)	0.3x0.5x1
Cooling Module	External Plate Heat Exchanger	1	0.6x0.6x1.5
Desalination Module	Water Desalination (RO Unit)	1	2.8x1.7x1.8***
Purification Module	Make-up H_2O & H_2 Purification	1	9.1x2.4x2.6+
Power Electronics	Electrolyzer Rectifiers	3	2.9x0.6x2++
	High-Frequency Transformer (400hz)	1	~0.8x2x2+++
	Inverter	1	5.96x1.28x2.46++

* Three 5 MW PEM electrolysis modules are needed to make a 15 MW PEM electrolysis system
**The equipment in each of the PEM modules can be fit in a standard 30 ft container frame
*** Single Pass only to produce drinking water quality. The water quality required for electrolysis is achieved in further purification steps (second pass RO and deionization) as part of the purification module
\+ assumed from reference concepts **[35, 100]**
++ Based on the size of current offshore wind turbine power converters of ~ 5 MW rating capacity
+++ Based on 1.65 m^3/MW for bio-slim type transformer, assuming that increasing the frequency reduces the volume proportionally **[101]** . In this case, the reference frequency (50 Hz) is increased to (400 Hz)

Electrolysis Module

The sizing of the electrolyzer stack is performed by assuming stack cells with effective areas[42] of 1500 cm^2 and rated capacities of ~ 2.5 MW (Thus a 5 MW electrolysis module would be comprised of two stacks). The assumed cell area and maximum power per stack correspond to sizes & capacities currently available in the market. Although technological trends indicate that cells with larger areas & capacities up to 5 MW are under development, the choice is made to maintain the 2.5 MW stacks due to it has a relatively low footprint contribution, and by recommendation of TNO experts in which smaller stacks would allow for easier offshore replacement[43]. A summary of the sizing characteristics are shown in Table 38 in the appendix.

The oxygen and hydrogen separators were sized to handle the mass flows of the anode and cathode products, respectively (streams 6 & 7 in Table 18). The oxygen separator is assumed to be horizontal for better process control of the large liquid flows that circulate on the separator [102] and to fit in standard container frames[44]. On the other hand, the hydrogen separator is set vertical, as much lower liquid flows need to be handled in this case. For both separators, the high volatility difference within the gases (hydrogen or oxygen) allows for a rapid degasification (~10s gas residence time[45]). However, as recommended by product vendors, the size of this system is constrained by the minimum liquid hold-up, which was recommended to be a minimum of 30 s. A summary of the sizing characteristics and assumptions are shown in Table 39 and Table 40 in the appendix.

The internal heat exchanger is sized based on the amount of heat that needs to be removed at the End of Life(EOL) of a module, as it is the state in which the highest heat losses are generated. As shown in Table 19, heat generation is estimated to be 1.4 MW per 5 MW module. As the heat is produced at low temperatures (~60 C), and the working pressure of the recirculation water process is also low (~5 bar), plate heat exchangers were selected to minimize the footprint of this equipment. In addition, note that the design assumes that the cooling water comes from a closed circuit (see Table 37 in Appendix) connected to an external seawater heat exchanger. A summary of the sizing characteristics is shown in Table 41 in the appendix.

As shown in Table 20 the oxygen separator utilises a larger footprint than the rest of the equipment in the module. The reason for this larger footprint is due to the large amounts of recirculating water that the oxygen separator handles, which are required for cooling down the electrolyzer system. However, footprint reductions of this equipment are expected as future improvements on the electrolysis energy efficiency would require less cooling media and, therefore, more compact separators can be desing. Further scaling up the separator (to handle flows of multiple modules) or even using vertical separators is also possible to reduce the total footprint. On the other hand, for the case of the hydrogen separator and the internal heat

[42] Effective areas correspond to the available area to perform the electrochemical reaction.
[43] Discussion with TNO experts indicate that the expected weight (< 5 tonnes) of 2.5 MW electrolysis stacks would facilitate replacement operations offshore.
[44] Current electrolysis manufactures provide containerized solutions
[45] From product vendors

exchange, this components are found to have relatively small footprints, so that no significant footprint benefits of further scaling up them can be obtained.

The estimated dimension of the different components of this module (with 5 MW capacity) are shown in Table 20. With the estimated sizes it is observed that the equipment can be fit into a 30 ft containerized skid. The dimensions of this module with the rated capacity is in alignment with recent PEM modules of similar capacity shown in the market [100].

External Heat Exchanger

The external heat exchanger sizing is based on the amount of heat that must be removed at the End of Life (EOL) for the complete electrolyzer system. Therefore, for the design, it is assumed that the water flow rate of the three 5 MW electrolyser modules is combined in a single stream for cooling.

As defined during the preliminary analysis, seawater is used to minimise the footprint of the cooling system. In this case, a plate heat exchanger was selected for the service. Similar to the previous case, the relatively low temperatures and pressures that need to be handled make this type of heat exchanger convenient to minimize the footprint of the cooling equipment. A summary of the sizing characteristics are shown in Table 42 in the appendix.

Note that this heat exchanger is in contact with seawater which is a highly corrosive medium. Indeed, seawater systems are considered part of the most maintenance-intensive system on offshore platforms [59]. Therefore, a spare plate heat exchanger would be needed as removing heat is critical to ensure the system's integrity.

Water Desalinator

The size of the desalination module depends mainly on the amount of water reacted for hydrogen production and the water losses resulted from carried over vapour water in the O_2 exhaust line (stream 8 in Figure 28). In this case, the maximum water requirements occur at rated power at the system's beginning of life (BOL), as there is a higher hydrogen production rate (and therefore, water consumption).

For a 5 MW electrolysis module, It was estimated that around 823 kg/h of water is required. Therefore, the total water needed for the 15 MW system would rise to 2470 kg/h, equivalent to ~60 $m^3_{distiillate}$/day (a more common metric in desalination systems). Note that future electrolysis developments with increased efficiency would result in higher hydrogen production and water consumption.

The seawater desalination size is determined in consultation with vendor's (see Table 43 in Appendix) as this system is already optimized for offshore applications to a minimized footprint. It is important to note that the shown dimensions are for a single pass reverse osmosis (RO) system capable of producing distillate up to drinking water purity only. The reason limit the RO system to produce drinking water quality is (as mentioned during the preliminary analysis) due to electrolyzer manufacturers typically ensure the water's quality going to the electrolyzer in their purification module.

In addition, a buffer vessel interfacing the water desalination system and the electrolysis system was sized to avoid frequent cycling of the RO unit. The frequent cycling is likely to occur at low electricity production due to a limited turndown of the RO unit (operating range 80-100 %)[46]. The vendor's recommendation is to reduce the desalinator's cycling (on/off) to less than five times per day. Therefore, to fulfil the previous requirements, a buffer vessel working volume of 1.65 m^3 was selected. This volume is equivalent to 7 h of uninterrupted water supply to the electrolyzer operating at minimum capacity. The reasoning for choosing operation at the electrolyzer's minimum capacity is because it is the mode of lowest power available, and therefore when the RO unit would cycle the most.

Another specific characteristic of the RO unit is that it requires daily backwashing to clean the seawater filter at the uptake point. This operation is automatic and expected to take around 15 min. In this mode, the water is supplied from the buffer tank, which can supply up to 30 min of water for operation.

Purification Module

The purification module, including the second water purification step and the H_2 purification equipment (de-oxo unit and dryer), is assumed to fit together in a single containerized module. Discussions with PEM electrolyzer vendors results that at scale of the design (15 MW) these packages would be designed to handle the full capacity of the electrolyzer system. The reasoning for this is the relatively small flows of (pressurized) hydrogen gas to be treated and water to be polished (streams 1 & 10 in Table 18, respectively). The sizing of these units requires knowledge of the intrinsic properties of the material used (e.g. for promoting the catalytic reaction in the de-oxo unit and the adsorption in the drying unit). This information tends to be proprietary information from vendor's and is not easily disclosed. Therefore, as a rough estimation, the components of the purification module are assumed to be fitted in a 30 ft (~9.1x2.4x2.6 m) container frame based on the dimensions of 10 MW and 20 MW concepts reported by the industry [35, 100].

For this specific module, after some analysis, it is proposed to move the hydrogen purification components towards the centralized collection point. The reason is that the hydrogen produced on the separators has already high purity to be transported from the turbine to a centralized collection point where further purification can be performed and therefore this process can benefit from economies of scale and simultaneously free space in the turbine. A potential identified risk of this proposal is that the oxygen and the hydrogen react in the transfer pipeline; however, this scenario is not expected due to the low concentrations of oxygen (below flammability limit), the low transport temperatures (the sea ground temperature is < 15 C), and the absence of a catalyst to drive the reaction.

Another risk of not having the H_2 purification step at the turbine is that condensation could occur in the transfer pipeline as the produced hydrogen is saturated with water[47]. This condensation could lead to liquid accumulation, pressure or flow rate fluctuations and corrosion[48] [103]. To overcome this potential problem, further cooling could be performed for the produced gas before sending it to a collection point.

Although the hydrogen purification step could potentially be relocated to the centralized collection point, still water purification is required to bring the water produced from the reverse osmosis(RO) desalinator to the quality required for the electrolysis system. For this case, RO product vendors were consulted to get

[46] From product vendors
[47] Note that the temperature at the seabed (where the array pipelines are buried) decreases with water depth.
[48] Depending of the pipeline material used for transport hydrogen.

insight on the size of a RO unit capable of purify the water to the electrolysis from which footprint dimensions of ~7x4x3 m (LxWxH) (not optimized for footprint) were provided. From this insight it appears that the main footprint contributor in the purification module is the water polishing equipment instead of the hydrogen purification ones. Therefore, for the design, the assumed size of the water purification module (30 ft container) is maintained.

Power Electronics

The final module that needs to be analysed is the power electronics of the integrated system. For this aim, Figure 31 depicts a simplified diagram of the electrical topology in a typical offshore wind turbine. In this figure, it can be seen that after stable AC power is produced (at the outlet of the back-to-back converter), a medium voltage step-up transformer (with its corresponding MW switchgear) is used to rise to the voltage of the produced power to deliver it to a centralized offshore substation where the voltage is further raised for transmission.

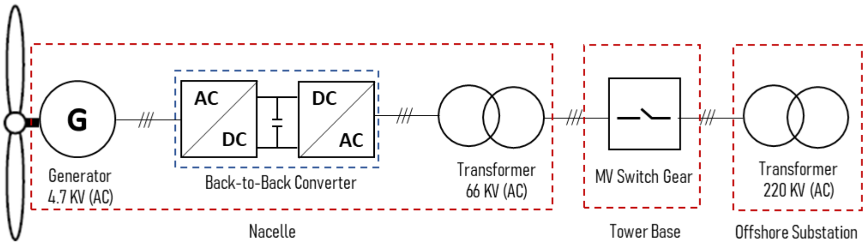

Figure 31 Simplified Current Electrical Topology of an Offshore Wind Turbine

When integrating the electrolyzer system with the turbine's power generator it is clear that equipment such as the medium-voltage step up transformer, switchgear, and the offshore substation are no longer needed. Therefore, a new electrical topology needs to be defined. For this aim a closer look is performed on the interfacing requirements between the generator and the electrolyser modules for which Table 21 summarizes their main electrical characteristics.

Table 21 Electrical Characteristics Within the System

Parameter	Note	Value	Parameter	Note	Value
Turbine Power[MW]	Rated	15	**PEM Module Power* [MW]**	Rated	5
Generator AC Voltage [V]	Line-to-Line	4770	**PEM Module Voltage* [V]**	DC	0.67
Generator Eq. DC Voltage [V]	DC Peak-to-Peak	7438	**PEM Module Current* [A]**	DC	6900
Generator Eq. Current [A]	DC	2017			

*Total Power for the module, it accounts for the stack, BOP, and PE ** For Stack beginning of life , and assuming that in a module two PEM stacks are connected in Parallel;

Initially, it was thought that the DC/AC conversion step in the back-to-back converter could potentially be removed as the electrolyzer system operates mostly with DC electricity[49] , and therefore, a single DC/DC

[49] Some Balance of the Plant equipment in the electrolyzer system need AC electricity

conversion step could be performed. However, as shown in Table 21, a relatively large voltage conversion ratio occurs within the produced voltage of the turbine generator (4.7 kV AC, equivalent to ~7.7 kV DC after the generator AC/DC converter) and the electrolyzer system (~0.67[50] kV DC). At this voltage ratio, DC/DC converters are not recommended due to their low conversion efficiencies [104, 105][51]. Therefore, a voltage step-down conversion step (and its footprint), which typically is performed with an AC transformer, appears to still be necessary for the integration.

Alternatively, to reduce the impact footprint of the step-down transformer, an AC coupling stage via a High-frequency transformer (HFT) could be used. In this case, it is possible to operate at higher frequencies as the system is not connected to a public grid. The main advantage of using an HFT is that it is more compact and efficient than traditional transformers. Besides, the use of the transformer also provides galvanic isolation[52] for coupling the system.

Figure 32 depicts a topology for the previously mentioned alternative. In this figure, an active AC/DC rectifier first controls the torque and voltage of the generator. Next, a central inverter sets the AC voltage acting as a slack node. The power is then transferred to the HFT to step down the voltage to the electrolyzer requirements. Finally, rectification is performed to supply DC power to the electrolysis modules. In this case, the group of AC/DC converters controls the power that is consumed by the electrolyzer. Note that in the figure it is assumed that the HFT and the rectifiers are located at the tower base. This arrangement is used to reduce ohmic losses resulting from the large currents (see Table 21) that are attained when the voltage is stepped down to the electrolyzer's module requirements.

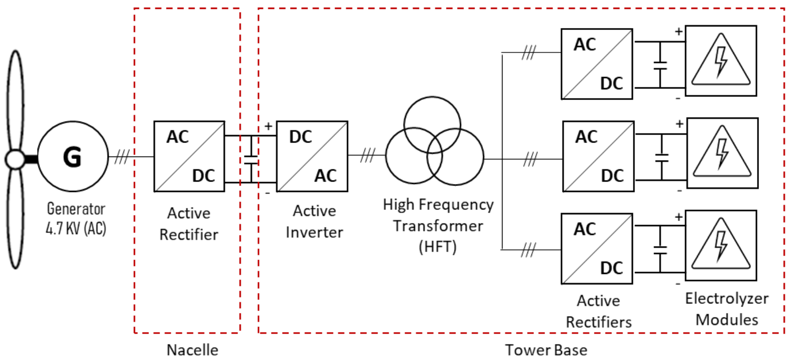

Figure 32 Simplified Integrated Electrical Topology

Note that a grid-connected transformer in Europe operates at 50 Hz, whereas from discussions with TNO experts, it is suggested that the HFT be operated at 400 Hz to reduce the footprint of this unit. This operating frequency is already used in other applications such as aircraft [106], where space & weight limitations also exist. The increase in frequency reduces the size of the transformer proportionally [101] and thus, the expected transformer size operating at 400 Hz is expected to have 1/8 the size of a transformer at 50 Hz of the same rating power. The transformer size was estimated using as a reference a bio-slim type transformer

[50] A single stack within the module operates at 0.67 KV DC. Stacks are assumed to be connected in parallel.
[51] Also from expert opinion
[52] Electrically separates the generator and the electrolyser, preventing unwanted current flows

used in offshore wind applications. This reference transformer operates at 50 Hz with a volume footprint of 1.65 m^3/MW (See Table 45 in Appendix C.6).

Finally, additional power converter sizes (for inverter & rectifiers) were estimated by taking as reference compact commercial power converters available for offshore wind applications (See Table 45 in Appendix C.6). As a remark, note that indirect footprint reductions are obtained from the fact that the integrated turbine is not connected to the public grid. In onshore applications, the power rectification step is usually performed by using "thyristor" based rectifiers, from which to comply with grid codes & standards additional equipment (and thus footprint) for filter and reactive power compensation is needed [107].

Note that the topology presented in this section is only a potential alternative. Future innovations could be directed to reduce the conversion steps further while keeping high conversion efficiency.

5.5.4 System Added Weight

In onshore electrolysis systems, the electrolyser's weight is generally not critical during the design process. However, for the turbine electrolyzer integrated system, the mass from the added systems can impact different items like the support structure requirements or installation & maintenance logistics. Therefore, insights on the potential added mass resulting from the integration were needed.

Although the weight of the main components in the PEM module can be estimated from the defined sizes in the previous section, this approach was deemed insufficient as many more elements (e.g. control cabinets, pipeline, skid structure, container) contribute to the total weight of the module/system. Therefore, the PEM module's[53] weight was estimated through product vendor consultations, TNO data, and industry publications. Figure 33 depicts the weight footprint of a (skid containerized) PEM Module as a function of its capacity.

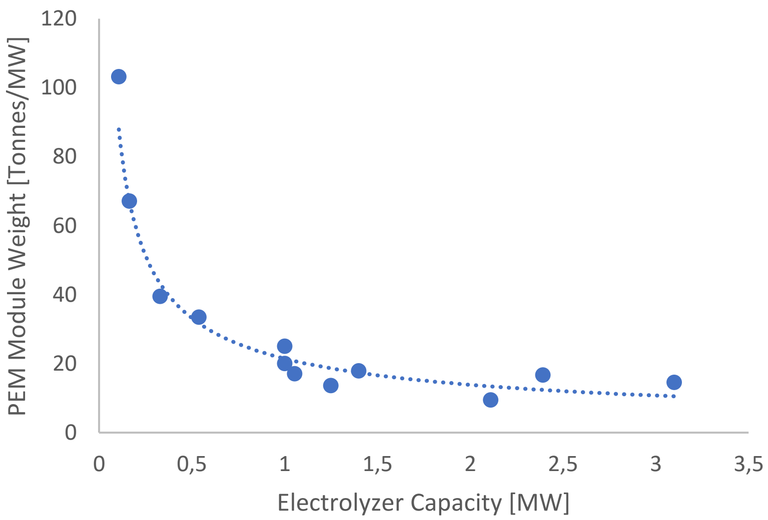

Figure 33 PEM Module Weight per MW at Different Capacities. Ref. product vendors, internal TNO data, and [84, 108, 109]

[53] A module consisting mostly PEM stacks, BOP (separators, internal pumps, heat exchanger), pipeline cabinets, control, skid frame among others. Excluding auxiliaries such as heat management, transformer, rectifiers.

As shown in Figure 33, there is a reduction in the electrolyser module's weight when increasing its capacity. This weight reduction is expected as savings from scaling up separators, required piping, and structural steel are obtained at larger scales. In the design, an electrolysis module weight of 15 tonnes/MW, corresponding to the highest reported electrolyzer module capacity (~3 MW) in Figure 33, is used for reference as the worst-case scenario. This information is validated with electrolysis product vendors, which estimate that PEM modules weights between 10 – 20 tons/MW are reasonable for modules capacities between 5 – 1 MW, respectively.

On the other hand, the purification module was also assumed to have 15 tonnes/MW weight footprint. This decision is made because at the scale at which the purification module operates (handle the production of 15 MW system), only recently demonstration projects have been completed[54] , and thus, no data is available.

With the previous assumptions, a rough weight addition of ~ 300 tonnes (worst case) from the electrolysis system can be estimated. This estimation considers that the three electrolyzer modules of 5 MW capacity and the purification module are the main contributors to the system's added mass. Equipment such as the plate heat exchanger for heat management with seawater(< 1 ton[55]) or the RO desalination system for water production (< 2 tons[56]) only add a few tonnes to the system and therefore are neglected.

On the other hand, discussions with electrolyzer vendors indicate that electrical equipment such as transformers and rectifiers could significantly contribute to the added mass. However, the previous claims are valid for the current electric technology used in onshore electrolysis. For the offshore electrolysis case, compact and relatively lightweight power converters are already available in the market (see Table 45 in Appendix C.6). In addition, it is assumed that the weight added by the central inverter and the high-frequency transformer compensates for the mass reduction from replacing the Medium Voltage transformer, Medium Voltage switchgear and inverters present in traditional offshore wind turbines. The added mass from the three electrolyzer side rectifiers (~2.6 tonnes for a 5 MW rectifier as shown in Table 45) have a minor contribution to the total added mass of the system.

Natural Frequency & Resonance

After discussion with TNO experts, the concern raised was whether the extra 300 tonnes from the electrolysis system would impact the natural frequency of the turbine's support structure and risk resonance[57]. The weight's impact structure natural frequency depends on where it is located; in this case, the electrolyzer system is expected to be located at the bottom of the turbine's or in the transition piece in which minimum impact on the natural frequency would be expected.

To verify if there is an impact on the natural frequency, simulations in OpenFAST using the 15 MW reference turbine were performed. OpenFAST uses a structural dynamics solver to estimate the frequencies of reactionary forces and moments present throughout the turbine structure (tower, transition piece, monopile). It separates the column height-wise into sections, which allowed for an approach wherein the

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[54] When writing this report the largest PEM electrolysis plant with a capacity of 20 MW has just recently be built
[55] Weight estimated from equipment sizing, see Table 42 in appendix
[56] From RO product vendors
[57] Resonance occurs when a natural frequency matches the turbine's rotational speed frequency.

properties of a section near the transition piece were modified to incorporate the added mass of the electrolyzer system.

The structure's frequency response was determined by applying a Fourier transform on the resulting side-to-side base reactions of the structure. For this aim, the Fourier Transform function available in MATLAB was used. Figure 34 (left) depicts the resulting frequency spectra of the side-to-side base reaction in the simulation.

In this figure, the red regions represent the operating ranges of the turbine blades. The blue line represents the structure's frequency response, and the dotted black line represents the natural frequency of reference (when no mass has been added). As shown in the figure (left), when the 300 tonnes weight is added at the transition piece, the peak response remains very close to the initial reference natural frequency. Therefore, suggesting that the impact of the electrolysis system's added weight in the support's structural response can be neglected in this case.

For completeness, the electrolyzer's mass was added into a higher turbine tower section, specifically the section 25 m below the nacelle. The resulting response is shown in Figure 34 (right), in which a moderate shift of the first natural frequency is observed. Discussions with TNO experts suggest that the monopiles & tower design for the reference 15 MW turbine might be conservative. However, the results fall in what is reasonably expected for the magnitude of weight added.

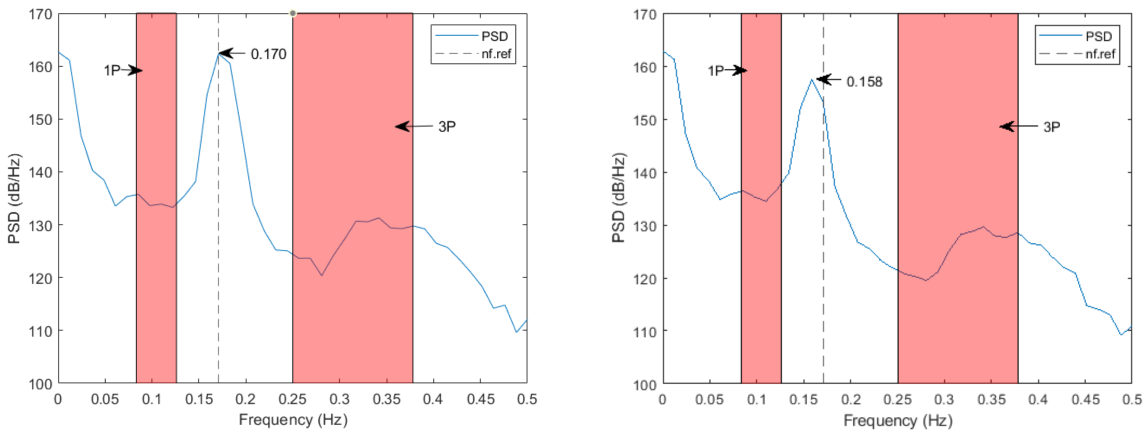

Figure 34 Electrolysis system weight impact on the natural frequency of the tower. (left) the system added at the transition piece (right) system added 25 m below the nacelle. In red is the operating range of the turbine, the black dotted line represents the natural frequency of reference (no mass added), and the blue line shows the structure frequency response.

Impact on Installation

To identify potential concerns regarding the impact of the added weight of the electrolyser's system on the offshore installations, discussions were conducted with TNO experts. The results of these discussions are summarized as follows.

The main concern in the installation phase was identifying whether independent actions would have to be performed offshore during the installation phase for the added systems. In this regard, the proposed solution was to merge the offshore installation activities of the transition piece and the electrolysis system by installing it inside the transition piece or on the platform of the transition piece. This solution implies that the assembly of the different systems in the transition piece can be performed onshore (thus avoiding costly assembly offshore), whereas offshore activities are limited to transport and position the combined system.

With this approach, the question remains whether different installation vessels were required to install the combined system, as the crane lifting capacity of the offshore installation vessels would have to account for the roughly 300 extra tonnes of the electrolysis system. Table 22 summarizes the masses of different components within the system, including the support structure for the 15 MW reference turbine as per design. As shown in the table, the weight of the transition piece is around 317 tonnes (as per the reference design); therefore, the weight would almost double when adding the electrolysis system. However, although this seems like a significant increase, it is essential to note that currently, the vessels used to install the transition piece are the same as the monopile installation. Therefore, these vessels need to have a much larger lifting capacity to handle the mass of the monopile piece (~1841 tonnes) during installation. Consequently, a transition piece with the electrolyzer system with a combined weight of ~617 tonnes is not expected to impact current installation methods significantly.

Note that the previous solution discarded the option to install the electrolysis system inside the turbine tower. The reasons for this decision are:

First, turbine towers are usually installed separately from the turbine foundation (monopile and transition piece). Therefore, installation vessels with lower lifting capacities (~ 850 tonnes) than those used for the monopile (~1841 tonnes) are required[58]. Adding the weight of the electrolyzer system to the turbine tower increases the lifting requirements of the installation vessel and, consequently, their costs. Second, although the tower could be split into two sections to reduce lifting requirements, an additional step for the offshore installation would be required, increasing the installation costs. Besides, to preserve the system's safety, the electrical equipment (such as transformers, inverters, rectifiers) is preferred to be physically separated from the hydrogen gas production and treatment. Finally, as discussed in the following sections, when placing the electrolyser system in an enclosed environment, several modifications would be required in the tower section, including venting, purging, and safety systems, which can impact the structural design of the turbine tower.

Table 22 Weight of the 15 MW substructure and the electrolysis system

Component	Mass [Tonnes]	Individual Component	Mass [Tonnes]
Complete Electrolysis System*	300	**5 MW PEM Module****	75
Transition Piece	317	**PEM Stack (2.5 MW)**	5
Monopile	1841	**Desalination Module**	1.8
Tower	852	**External Heat Exchanger**	0.55

* Estimated for 3x 5 MW Modules (PEM stack & BOP)+ 1x Purification module (assumed weight equivalent to one 5 MW module)
** Assuming 15 tonnes/MW as shown in Figure 33**.** Conservative estimation, further scaling up of BOP can further reduce this mass

[58] Discussions with O&M experts warn that although ideally an installation vessels with the right lifting capacities would be chosen the market availabity could force the use of vessel with higher lifting capacities and costs

5.6 Physical Integration System concepts

It is clear that although footprint reductions can be attained in the electrolyzer system, modifications are still required to perform the physical integration with the wind turbine. As mentioned in the previous section, integrating the electrolyzer system with the transition piece was preferred over the turbine tower due to the potential advantages in the offshore installation that can be obtained. With this premise as a basis, two main concepts were generated for the design. The concepts shown in Figure 35 were based on the footprint characteristics estimated in section 5.5.3.

In the first concept (shown in Figure 35(left)), it is proposed to integrate the electrolyser system (and added systems) inside the transition piece, whereas in the second concept (shown in Figure 35 (right)), it is proposed to enlarge the transition's piece working platform to integrate the systems. Further description of these concepts is given in the following sections.

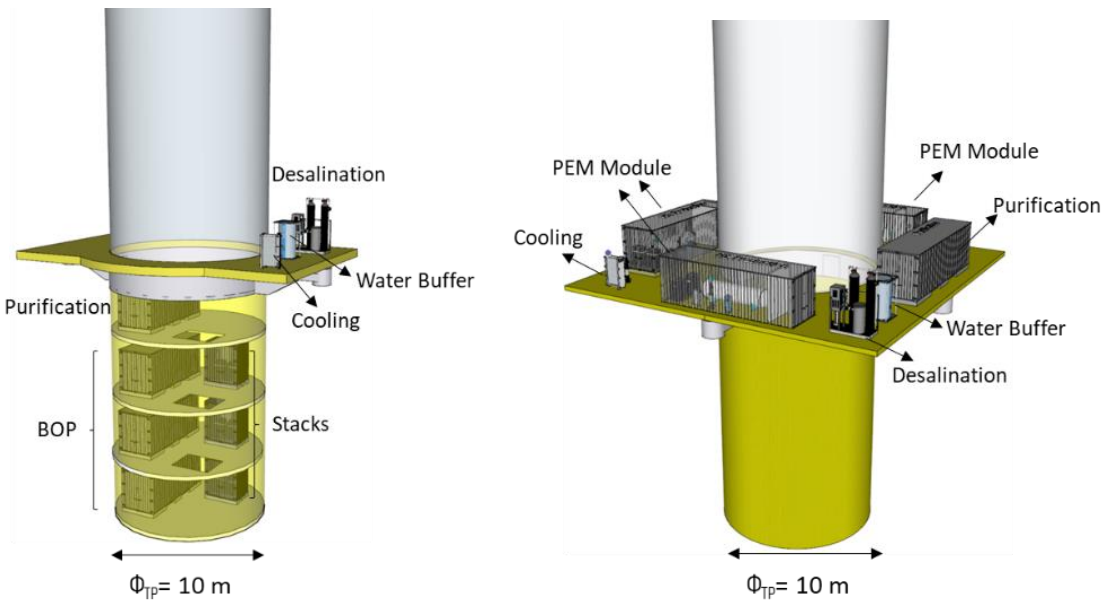

Figure 35 Turbine-Electrolyzer Integration Concepts for a 15 MW System; (left) inside the transition piece (TP); (right) on an enlarged TP platform. PEM modules containing electrolyzer's Balance of Plant (BOP) and Stacks

5.6.1 Integration Inside the Transition Piece

This concept addresses the initial idea of integrating the electrolyzer system inside the substructure of the offshore turbine. This concept is conceived to integrate the electrolyzer system inside the transition piece of the support structure. However, for the case in which the integration is preferred inside one (or more) sections of the tower base, similar analysis and issues as the ones discussed in the following sections apply.

For this concept, the (three) 5 MW containerized PEM modules (each estimated L:9.1xW:2.4x H:2.6 m) do not physically fit in the space available of the transition piece (ø=10 m) and therefore had to be rearranged to accommodate the equipment. Therefore, as shown in Figure 35 (left), the PEM modules are split into two individual containerized skids, one containing the balance of the plant (BOP) and the other containing the PEM stacks. The split 5 MW modules are distributed throughout the height of the transition. A similar treatment is performed for the purification module to distribute its footprint area among the space available in the transition piece. On the other hand, the external cooling heat exchanger and the desalination system are placed on the platform of the transition piece as they utilise a relatively small footprint. Finally, it is assumed that electrical equipment such as the high-frequency transformers, inverters and rectifiers can be installed inside the turbine's tower base (not shown in the figure), as per the dimensions of this equipment estimated in the previous section (see Table 20).

Note that in the figure pipeline routing, vents are not included as detail design is not part of the scope of this study. However, these elements are discussed during concept selection in the following section.

5.6.2 Integration on the platform

The second concept proposes enlarging the working platform of the transition piece to accommodate the electrolysis system (and other systems). Figure 37 (right) shows that the three 5 MW modules, a purification module, a desalination system (with water buffer) and the cooling systems are distributed around the enlarged platform. In this case, the size of the different systems estimated in the previous section (see Table 20) is kept. In addition, similar to the previous case, electrical equipment such as the high-frequency transformers, inverters and rectifiers can be installed inside the turbine's tower base (not shown in the figure), as per the dimensions of this equipment estimated in the previous section (Table 20).

Note that in the figure, pipeline routing, vents and additional steel for supporting the platform are not included as detail design is not part of the scope of this study. However, these elements are discussed during concept selection in the following section. In addition, note that current PEM electrolyzer modules found in the market already include safety (O_2 and H_2) ventilation systems within their product packages.

5.6.3 Concept selection

The two proposed concepts were analysed during the selection process regarding their potential impact on maintainability, offshore installation, inherent safety, and required structure modifications compared to a typical monopile fixed offshore wind turbine in which no electrolyser has been integrated.

After the analysis, the concepts were qualitatively rated according to their potential issues and expected modifications resulting from the integration. The scoring system for the parameter evaluated is: (++) when no issues or modifications were identified, (+) for minimal issues or modifications needed, (-) when some issues or modifications are needed, (--) for major issues or modifications identified. The analysis and score assigned were based on feedback/discussions from TNO experts after the concepts were presented. Table 23 depicts the resulting scoring from the previous selection process.

Table 23 Comparison Between the Proposed Concepts

Parameter Impacted	Concept 1 Inside the Transition Piece	Concept 2 On the Platform
Structure Modifications	- -	-
Maintainability	- -	+
Offshore Installation	+ +	+
Inherent Safety	- -	-

+ + No major issues/modification**;** **+** Minimal issues/modifications;

- some Issues/modifications; **- -** Major issues/modifications

Further description of the reasoning behind the scoring in Table 23 is described below.

Structure Modifications

The "inside the transition piece" concept is expected to require major structure modifications, such as:

- Internal platforms would need to be installed in the transition piece to support and fix the PEM & purifications modules. In addition, these platforms need to be designed to handle the added mass of each module (~75 tonnes per module).
- In addition, structural modifications are needed to include connection points and pipelines for desalinated water, cooling seawater, and the produced hydrogen.
- The electrolyzer modules need to be re-arranged (from the containerized skid) to be able to fit in the structure
- Besides, venting, purging lines and air conditioning in/outlets need to be added in the transition piece to ensure the safe operation of the electrolysis system. An important aspect to consider is that these lines need to be placed above the splash zone of the substructure and far from the turbine entry to avoid put personal and equipment in danger.

For the "on the platform" concept, the main structural modifications concern the enlargement of the external platform of the transition piece to include the new systems. For the arrangement shown in Figure 35, it is estimated that the platform would have to extend five meters from the outer diameter of the transition piece in all directions. In addition, the platform would have to be re-designed to support the extra mass of the additional systems (~ 300 tonnes).

Inherent Safety

A major concern for the "inside the transition piece" concept is the increased risk for operation and operators (e.g. during maintenance operations) as the entire group of electrolyzers are placed in an enclosed environment. This case implies, for example, that in case of hydrogen leakage (from any of the electrolyzer stacks or balance of the plant), or when exchanging an electrolyzer stack, the whole atmosphere within the transition piece can potentially become explosive. Therefore, the risk is bound to the whole transition piece structure. Furthermore, depending on how well the isolation between the transition piece and the tower base is made, the risk can even extend to the transition tower.

On the other hand, for the "on the platform" concept, some inherent safety issues are still perceived as hydrogen production still occurs in a confined space (the 30 ft containerized skid). However, for this case, the risk is bounded within the individual containerized modules and thus its effect. For example, if one electrolyser module's safety system triggers and shuts it down, the other modules could potentially continue operating as they are physically isolated from each other.

In both cases, having hydrogen in confined space creates a potential risk of hydrogen gas built up and thus the creation of explosive atmospheres. However, these risks are expected to be manageable by adding safety systems with strict monitoring and control. For the “on the platform” concept, current PEM electrolyzer systems that operate in containerized modules are already available in the market. As a reference, the operation of 5 MW containerized PEM modules scale is currently being demonstrated in pilot projects[59]. For the “inside the transition piece” concept, a similar safety principle can be followed. However, as mentioned before, several adaptations to the support structure would need to be performed.

In addition, note that in case of a sudden power outage, current PEM electrolyzers can also safely depressurize and shut down, thanks to the pressure differential capabilities of the membrane in the PEM electrolyzer. However, from discussions with industry experts, a point that needs further revision in the design, independent of the selected concept, is the effect of sending back the condensed water from the H_2 gas-liquid separator to the water recirculation loop in the oxygen separator. In this case, industry experts warn that in case of multiple failures of the control system in this section, an O_2/H_2 hazard can evolve.

Offshore Installation

For the “inside the transition piece” concept, providing that the electrolyser system assembly is performed in the transition piece onshore, no significant differences were identified at this design stages, with current offshore installation methods. Therefore, the same installation vessels used to install current transition pieces could potentially be used with the integrated system.

For the “on the enlarge platform” concept, it is also assumed that the electrolysis system is assembled in the transition piece platform onshore. In this case, the only potential minor issue is that the larger platform area and equipment exposed to air could decrease the weather window for installation.

Maintainability

For the “inside the transition piece” concept, the main disadvantage in terms of maintenance is that the equipment inside the transition piece is more difficult to access. In addition, the logistics for equipment replacement need to be reconsidered. For example, when equipment replacement is required, a lifting crane (installed inside the tower base) would need to lift the equipment from the transition piece and through a door in the tower base before transferring it to a second crane (installed outside the tower base). This second crane would need to transfer the equipment to a vessel (e.g. service operation vessel). A similar reversal procedure would need to be performed to lower the new equipment into the transition piece.

Ideally, the main equipment that needs to be replaced from the electrolysis system is the PEM stacks. This equipment has a relatively small footprint (LxWxH: 0.8x0.55x1.65 m for a 2.5 MW stack) and technically fit through the turbine door[60]. However, if there is any problem with larger equipment such as the oxygen

[59] In 2021 cummins started operation of a 20 MW PEM electrolyzer system with 5 MW modues at the Air Liquid hydrogen production facility in Bécancour, Québec.

[60] As a reference a (LxWxH m) 2.66x1.17x2.65 transformer fits through the door of a 5 MW offshore turbine

separator or a long pipeline, it cannot be replaced (as it will not fit through the turbine door); instead, reparation works would have to be performed inside the transition piece, thus increasing the time (and the cost) of offshore operations.

For the “on the enlarge platform” concept, the main advantage is that the equipment is readily accessible, and thus, much more straightforward logistics(compared to the previous concept) can be employed to maintain the system. For example, replacement operations could be performed with a lifting crane (located on the platform), which directly transfers the equipment to a service vessel. In addition, with this approach, it is possible to replace large equipment or even a complete module to minimize offshore operations (such as perform repairing works onsite).

The principal disadvantage in the “on the platform” concept is that much more equipment (such as containers & pipes) is exposed to offshore conditions so that more frequent maintenance is likely. However, access is much more easy, and still the main equipment (stacks, exchangers, pumps, etc) is expected to be protected as it is inside the container.

Final Selection

Although both concepts can be technically engineered, the enlarged transition piece concept is selected as the most feasible option. It provides much more simplicity in terms of maintenance logistics than the ones required when installing the added systems inside the transition piece. The selected concept also requires less complex structure modifications in the transition piece, as only the external working platform is modified. The challenge of enlarging the external platform is creating sufficient deck space to accommodate the added systems and ensure that the platform can support the added mass from the new systems. Finally, in terms of inherent safety, both concepts operate in enclose environments; however, the risk is perceived as higher in the “inside the transition piece” concept as the whole system is grouped in a single environment; in this case, the whole transition piece can become an explosive zone when for example hydrogen leakage occurs.

5.7 Summary of Findings

- During periods of low wind speeds, modularity of the electrolyser system combined with a control strategy is required for safe operation. In the design, the 15 MW electrolysis system is split into three independent 5 MW modules to comply with this requirement.
- At operating periods close to the cut-in wind speed of the wind turbine, repetitive short-term gaps of energy production could potentially risk the safe operation of the electrolyser system. It is suggested the use of buffer storage technologies such as supercapacitors to handle this issue.
- The maximum power step change (<9.7 %/s) of the large scale 15 MW reference turbine matches the dynamic capabilities of industrial electrolyser systems (~10%/s).
- Some footprint reductions opportunities resulting from the integration are:
  - The use of sea water plate heat exchangers (instead of air cooling used in onshore PEM electrolysis) results in a compact cooling system to remove the electrolysis's excess heat.
  - The main opportunity for footprint reduction in the electrolyzer's module is scaling up the oxygen gas-liquid separators. In the design, the equipment scaling up was limited to handle the capacity of electrolysis modules up to 5 MW to maintain the system's modularity. Further footprint reductions are expected in the future with more efficient electrolyzer systems. In addition, no stoppers are expected for further scaling up the gas-liquid separator when more footprint reductions are needed.
  - Power electronics in 'onshore' PEM electrolysis systems have a significant area footprint due to the technology used and to comply with grid requirements. For the integrated system, besides not having the grid requirement, compact power electronic technologies (converter & rectifiers), with load following capabilities, already used in offshore wind turbine application can be employed.
  - The relatively high voltage ratio between the turbine generator and the electrolyzer modules suggests that a step-down transformer is still required for electrical integration. However, as the integrated system is not connected to a public grid, it is suggested to use a high-frequency transformer (e.g. operating at 400 Hz). The increased frequency is expected to reduce the equipment footprint proportionally.
  - It is recommended to move the hydrogen purification step to the centralized collection point to free space in the turbine. However, further verification is needed to ensure that the traces of water and oxygen in the transferred hydrogen stream do not impact the pipeline negatively.

- The additional weight resulting from the integration was roughly estimated in the order of 300 tonnes. This added mass is not expected to have influence in the natural frequency of the support structure when it the added system is placed at lower section turbine's support structure.
- The electrolyser's impact on offshore installation cost can be minimized by combining this system with the transition piece onshore. The combined system would then be installed offshore as per traditional installation methods. The added weight is shown to be within the capabilities of the required transportation and lifting equipment.
- Two integration options were proposed for the combined system: internally within the transition piece or on an enlarged external platform surrounding the transition piece. From a comparison of the two options, the external integration option was chosen due to fewer structural modifications, less complex maintenance logistics, lower difficulty of access, and lower perceived risk.

6 Economics

In this section, an economic assessment to estimate the Levelized Cost of Hydrogen (LCOH) of the design concept selected is performed. To this aim, first, reference & future case scenarios are defined for the analysis. Next, the cost model and main assumptions made during the analysis are discussed. Finally, the resulting LCOH using current technology and of expected future developments are shown and analysed.

6.1 Case scenarios

6.1.1 Reference Case & 2020 Scenario

To identify the economic benefits of integrating the offshore wind turbine and the electrolyzer, two main study cases, namely "onshore electrolysis" and "offshore electrolysis", are defined.

The onshore electrolysis case consists of a 'typical' offshore wind farm architecture where all the electricity produced is transmitted to shore using an electrical infrastructure composed of inter-array cables, offshore/onshore substations, and export cables. Then, an electrolyzer system at the shore uses all the electricity to produce hydrogen. Finally, the hydrogen is assumed to be injected into a gas network for further distribution.

On the other hand, the offshore electrolysis case considers that an offshore gas infrastructure replaces the offshore electrical infrastructure to transport the produced hydrogen from the wind turbines up to the injection point of the gas network. The gas infrastructure consists of transfer pipeline manifolds, an offshore compression substation, and export pipelines.

Both cases are evaluated at the same site conditions, corresponding to Ijmuiden Ver. Location for a predefined wind farm size of 720 MW. The wind farm is populated with offshore wind turbines of 15 MW capacity. In addition, each turbine is assumed to contain PEM electrolysis modules that combined also have a rated capacity of 15 MW. The gas network is assumed to receive the hydrogen gas onshore at 80 bar, which is in the range (70-100 bar) of current operating pressures for onshore gas pipelines [54, 9]. The compression and pipeline systems are thus sized in the offshore electrolysis scenario to ensure hydrogen at 80 bar reaches shore. Table 24 summarizes the shared characteristics for the studied cases. Further descriptions of the wind resource and sea characteristics used in the analysis are shown in Table 46 and Table 47 in Appendix D.

Table 24 General Scenario Characteristics

Parameter	Value	Parameter	Value
Wind Farm Rating [MW]	720	**Project [Year]**	2025
Wind Turbine Rated Power [MW]	15	**Project Lifespan [Years]**	20
# Turbines	48	**Electrolyzer- Turbine/Farm Rated Capacity [-]**	1:1
Weather Ref. Location [-]	Ijmuiden Ver	**WAAC (nominal) [%]**	4 [110]
Water Depth* [m]	35	**Injection Pressure to Gas Network [bar]**	80
Distance to Shore [km]	62	**Soil Type [-]**	Sand

* Water depth varies between 28 to 40 m. In this case, 35 m is used for simplification

6.1.2 Potential PEM Electrolysis Cost Reductions

At the time of writing this report, PEM electrolysis is a technology in the early commercial stage, implying that future technology developments and cost reductions are still expected. In particular, increasing market volume and standardization of manufacturing processes are expected to reduce the Capex cost of PEM technology. On the other hand, technology developments at the PEM cell level are expected to improve the efficiency of hydrogen production, which helps reduce the Levelized Cost of Hydrogen (LCOH) as defined in equation (4). These aspects were considered during the economic analysis from which the main assumptions are described below:

- **PEM manufacturing standardization:** these cost reductions are implemented in the cost analysis by applying learning factors for the cost components of the stack, the balance of the plant (BOP) and power electronics. The learning factors are sourced from in-house analysis at TNO, based on quotations, public sources and discussion with OEM. The learning factors and resulting cost reductions can be found in Table 49 in the appendix.
- **PEM Electrolysis Efficiency Increase:** the efficiency increase is implemented by extrapolating some of the parameters in the electrochemical model (used to calculate the hydrogen energy yield) to what could be expected in terms of technology advancements into a 2025 scenario. The extrapolation factors are the result of discussions with TNO experts. These factors and the reasoning behind the extrapolation can be found in Table 34 in the appendix.

6.2 Cost Models & Assumptions

The economic calculations used an in-house TNO cost tool initially developed to estimate offshore wind farms' Levelized Cost of Electricity (LCOE). For the LCOE calculation, the in-house tool determines the wind farm energy yield and the turbine, support structure, electrical system, farm installation, and operation and maintenance (O&M) costs.

For this project, the tool is modified to include engineering cost models representing the added systems, such as water desalination, electrolyzer systems, transfer[61] & export pipelines and onshore/offshore compressor substation. Likewise, an equivalent wind farm hydrogen yield is calculated. The objective of these modifications is to estimate the Levelized cost of hydrogen (LCOH) for the assessed scenarios.

Depending on the assessed scenario, some cost models (including the added ones) might not be applicable. For example, the electrical infrastructure is no longer necessary for the offshore electrolysis case, whereas the hydrogen infrastructure (such as pipelines and offshore compressor substation) is. A summary of the cost models applied for each scenario can be found in Table 24 in the appendix.

The Levelized Cost of electricity is calculated based on:

[61] Transfer pipelines, deliver the produced hydrogen from the turbine to a centralized collection point where the offshore compression substation is located

$$LCOH = \frac{\frac{CAPEX}{a} + OPEX}{AHY} \quad (4)$$

Where $CAPEX$ is the total capital expenditures, $OPEX$ are the annual operational expenditures, a is the annuity factor, and AHY is the annual hydrogen yield.

The annuity factor is calculated as:

$$a = \frac{1}{\sum_t^n (1+r)^{-t}} = \frac{1-(1+r)^{-n}}{r}$$

Where r is the discount rate, t is the year index, and n is the project's lifespan.

To calculate the Levelized Cost of Hydrogen (LCOH), several models and assumptions of the systems and their components were made. These models and assumptions are described in the following subsections.

6.2.1 Wind Turbine & Support structure

In the TNO cost tool, the wind turbine cost model estimates the mass and the cost of the wind turbine's rotor-nacelle assembly (RNA) as a function of characteristics such as rotor diameter and turbine rated power. This cost model was kept unchanged for both of the scenarios analysed.

On the other hand, the support structure cost model estimates the masses of the tower, transition piece and foundation monopile. In this model, the support structure is first sized based on a check of the structure's natural frequency. Then, the estimated masses are used to calculate their cost based on the construction material prices for the three components.

For the offshore electrolysis case, a penalty factor is added to the transition's piece to account for the structural modifications needed (such as enlarging the working platform) to accommodate and support the added systems for electrolysis. At this point of the research, there is a large uncertainty on the transition's piece cost increase resulting from the structural modifications; however, a 50 % extra cost for the transition piece was assumed as a basis for the economic analysis. The impact of the previous assumption on the LCOH is checked for sensitivity in section 6.3.3.

On the other hand, the monopile cost is assumed to remain invariant for both of the scenarios assessed. The reason for this decision is that no modifications to, for example, fulfil the natural frequency requirements of the structure are expected when adding the electrolyser system(see section 5.5.4).

6.2.2 Energy & Hydrogen Farm Yield

In the TNO cost tool, the annualized energy yield is determined based on the turbine power curve and the wind resources characteristics at the site. In addition, the model uses a predefined wind farm layout to estimate the wake losses and efficiency of the wind farm. Thus, the main output of the model is a corrected (for wake losses) annualized energy yield for the complete farm.

In this project, to calculate the LCOH, a hydrogen yield[62] instead of an energy yield is required. Therefore, for this aim, instead of using the power curve of the wind turbines (used to calculate power production at a particular wind speed), an equivalent 'hydrogen curve' is used. The procedure to construct such a 'hydrogen curve' is as follows:

- The electrochemical model discussed in section 5.2 is used to generate hydrogen production vs power input curves. For the economic analysis degradation was taken into account by averaging the cell voltages between the beginning and end of life. Next, as the electrochemical model is not explicit for hydrogen production at different powers, the previous curves are fitted to a second-order polynomial to facilitate their use (see Figure 51 in the appendix).
- Next, a power curve (power vs wind speed) is generated using a calculator tool from the INNWIND project [111]. The calculation tool includes a generic model for the turbine's drive train efficiency at partial and full load.
- Next, a generic model for the electrolyzer's Balance of Plant (BOP) efficiency at partial and full load is included to account for the energy used by this equipment(which cannot be used to produce hydrogen). The BOP efficiency was obtained by fitting an electrolyzer's BOP performance curves for a 'typical' electrolyzer system[16] (see Figure 50 in the appendix).
- Finally, the hydrogen curve (hydrogen production vs wind speed) is obtained by combining the previous models. The power production of the turbine (at different wind speeds), corrected by the drive train efficiency and the BOP efficiency, is the input for the fitted hydrogen production model.

Note that for the construction of the hydrogen curve, two main assumptions were made. First, the electrolysis system in the turbine has the same rated capacity as the turbine generator. Second, the electrolyzer system has a sufficient level of modularization to safely operate at all the operating ranges of the wind turbine (see discussion in section 5.4). An example of the hydrogen power curve obtained by following the previous procedure can be found in Figure 52 in the appendix.

For the onshore electrolysis case, the power losses of the electrical transmission system impact the hydrogen production yield as less electrical energy is available. Therefore, the electrical losses were assumed to result in a ~ 2 % decrease in energy yield production, which was also assumed to decrease the hydrogen yield production equivalently. The assumed 2% electrical losses are in the range of accepted electrical losses for current transmission systems [112, 113, 114].

6.2.3 Offshore Installation

In the TNO cost tool, wind farm offshore installation costs are determined by several parameters such as distance from shore, turbine characteristics, number of turbines/substations, and installation strategy. In addition, the tool estimates installation costs for the turbines, support structures, electrical substations, and inter-array & export pipeline. The tool is used as given for the onshore electrolysis case.

For the offshore electrolysis case, two main assumptions were performed. First, providing that the electrolysis system (and auxiliaries) is preinstalled onshore into the transition piece, there is minimum impact on the wind farm's offshore installation cost. The reason for this assumption is that current installation vessels have already the lifting and cargo capacity necessary to handle the additional mass

[62] Hydrogen yield refers to the hydrogen production after wake losses have been taken into account

applied into the transition piece when the electrolysis system (and auxiliaries) is integrated (See discussion in section 5.5.4)

Second, the TNO tool can include activities (and therefore costs) for pipeline installation (e.g. laying and burying pipeline). However, these activities were not explicitly included in the TNO tool as the available offshore pipeline data already includes offshore installation in the reported cost values.

6.2.4 Electrolyzer

Capital Cost

The current (2020) electrolyzer system's capital cost corresponds to in house analysis at TNO from vendor quotations, public sources and discussion with OEM[63] for systems at a 1 MW scale. This capital cost is composed of the electrolyzer stack, balance of the plant, and power electronics costs.

As this cost corresponds to electrolyzer's systems at a 1 MW scale, a scaling rule was applied to estimate cost reductions resulting from manufacturing equipment at large scales. The scaling rule utilised is:

$$Cost_{equipment,new}\left[\frac{€}{KW}\right] = Cost\ _{equipment,ref}\left(\frac{P_{new}}{P_{ref}}\right)^{f} * \frac{P_{ref}}{P_{new}}$$

Where $Cost_{new}\ \left[\frac{€}{KW}\right]$ is the cost at the new scale, $Cost_{ref}\ \left[\frac{€}{KW}\right]$ is the reference cost (1 MW scale in this case), $P_{new}\ [KW]$ & $P_{ref}\ [KW]$ are the scaling parameters (the electrolyser power), and $f\,[-]$ corresponds to the scaling factor.

As the components in the electrolyser system do not have similar cost benefits when scaling up the system, different scale factors (see Table 50 in the appendix) were assigned to the electrolyzer stack, balance of the plant and power electronics. Besides, the scale rule is applied considering the number of modules at which the system is composed. For example, a 15 MW system composed of three 5 MW modules will have economics of scale only for scaling from 1 MW to 5 MW systems instead of 15 MW[64].

The previous reference cost was available only for systems designed for onshore applications. However, for the offshore electrolysis case, an increase in cost is expected due to potential modifications required to ensure the systems' durability in an offshore environment. Therefore, a marinization cost penalty factor of 15% extra cost is introduced and added to the system uninstalled capital cost. This figure is in the range of marinization penalty factors reported/expected in the literature for turbines [115] and electrolyzers [9].

Operational Cost

The electrolyzer's annual operational cost (excluding electricity and stack replacement (discussed separately in the following subsection) are reported in the literature to be in the range of 2-5 per cent of the electrolyzer system's initial capital per year ($\%_{CAPEX,initial}/year$).

As the previous figures are sensitive to the size of the electrolyzer system (e.g. by reducing labour cost for larger systems), the approach of further separating the annual operational cost into consumables and

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[63] OEM= Original Equipment Manufacturer

[64] Here it is assumed that each modules has its own balance of the plant, future improvements can include for example a single BOP system for the whole system, for which further economies of scale can be reached.

labour cost is used, as reported in the literature [116]. In this approach, consumables cost were fixed into 1.5 % of the initial Capex per year, whereas the labour cost is a function of the system's size. For this case, the labour cost incurred for a 15 MW capacity system is estimated (based on [116]) to add ~0.5 % of the initial Capex to the annual operational cost per year. A summary of the reported annual operation cost as a function of the system size can be found in Table 51 in the appendix.

In addition, as the annual operational cost figures previously presented are available only for systems operating in onshore applications, an offshore penalty factor is introduced. This offshore penalty is only applied to the labour cost, whereas the consumables cost factor is maintained constant (~1.5 % of the initial Capex per year). The reason for this is that labour costs are expected to increase when performed offshore, whereas the consumables cost remain constant (note that a marinization factor was already applied to the Capex cost for the case of offshore electrolysis). At this point of research, it is highly uncertain how much the annual operating cost would increase due to offshore labour cost, as no offshore electrolysis systems are operating yet. However, due to the higher logistics costs to perform operations offshore, as a first estimation, offshore labour costs are assumed to be double (thus a penalty factor of two) compared to onshore. This figure is highly uncertain as the annual electrolyzer's annual operational cost could potentially be optimized by, for example, integrating it with the wind turbine's one.

Stack Replacement

Due to the continuous degradation of the electrolyzer stack, a stack's replacement cost needed to be included in the cost model. The number of stack replacements required during the project lifespan (assumed 20 years) is determined from the stack lifetime (~ 80000 operating hours) and the capacity factor of the wind turbine (for the 15 MW reference turbine ~60%). In addition, the net replacement cost is estimated to be a function of three elements: the new stack cost, the old stack residual value and the stack installation cost.

The new stack cost is determined from the in-house reference cost provided by TNO (see Table 49 in the appendix). Like the initial Capex estimation, the stack's reference cost is updated to the system's scale using the scaling rules presented before.

The old stack residual value is estimated assuming that only 50% of the stack's material cost can be recovered. The recovery factor is estimated assuming that some components of the electrolyzer stack, such as the bipolar plates (corresponding to ~50 % of the stack's material cost [6])), can recover their value easier than, for example, the catalyst coated membrane (which has incurred in degradation).

From the in-house reference cost provided by TNO, the installation cost of a new stack corresponds to 20 % of the initial stack's Capex investment. This installation figure is assumed to be equivalent to the installation of the replacement stack. When the previous assumptions are applied to the reference cost provided by TNO for a 1 MW electrolysis system, the resulting replacement cost (including installation) corresponds to ~30% of the electrolyzer initial installed Capex investment. This figure is in the range (15-36 % of the electrolyzer initial Capex investment) of the stack's replacement cost reported elsewhere [117, 17, 118].

For the case of electrolysis offshore, an offshore installation penalty factor is introduced. At this point of research, it is highly uncertain how much the replacement installation costs will increase when performing the replacement offshore (as no offshore electrolysis systems have been installed or replaced offshore yet). Therefore, as a conservative estimation, similar to the previous case, the replacement installation cost is assumed to be doubled (thus a penalty factor of two) offshore compared to the onshore case. The impact of the previous assumption on the LCOH is checked for sensitivity in section 6.3.3.

6.2.5 Desalination Unit

For the offshore electrolysis case, the cost of reverse osmosis is taken from vendor quotes at the relatively small scale of this system, which is found to be in the range of 3000 €/m_{water}^3/day. On the other hand, in the onshore electrolysis case, centralized (and larger scale) water desalination units can be used. For larger desalination units, vendor quotes provided the figure of ~1500 €/m_{water}^3/day, which is in the range of large scale desalination units reported in the literature [66, 67, 68].

6.2.6 Hydrogen Compression

The Capex of the compressor is determined from the compressor's duty(or power) required for the service, which is a function of the gas mass flow rate (and its intrinsic properties), temperature, and the desired compression ratio, as shown in equation (5).

$$Power_{Compressor}[watts] = m\,\frac{RT_{in}}{MW}\frac{\gamma}{\gamma-1}\frac{Z_1+Z_2}{2}\;\frac{1}{\eta_{iso}\,\eta_m}\left[\left(\frac{P_2}{P_1}\right)^{\frac{Z_1+Z_2}{2}}-1\right] \qquad (5)$$

Where m [kg/s] is the gas mass flow rate; P_2 [bar] and P_1[bar] are the discharge and suction pressures, respectively; Z_2[-] and Z_1[-] are the gas compressibility factor at suction and discharge; T_{in}[K] is the inlet temperature, γ the specific heat ratio; MW is the molecular mass of the gas, η_{iso} & η_m correspond to the isentropic and mechanical efficiency of the compressor, respectively, and R is the universal gas constant.

For the offshore electrolysis case, the suction pressure is determined from 2 design variables: the electrolyzer operating pressure (assumed 30 bar) and the allowed pressure losses in the transfer pipeline to the collection point (assumed 2 bar). On the other hand, after discussing with TNO experts, the discharge pressure is set to 100 bar. The reasoning for this decision is that this pressure corresponds to a reasonable transmission for offshore pipelines operating in the North Sea. Likewise, the available pipeline cost (explained in the following section) was obtained for pipelines operating around this pressure; higher pressures will increase the required thickness of the pipeline, for which no data costs were available. In addition, 100 bars is found to be sufficient discharge pressure to ensure that the produced hydrogen enters the gas network at the required injection pressure (80 bar)[65].

On the other hand, for the onshore electrolysis case, a compression system was also included to increase the electrolysis pressure (~30 bar) to 80 bar, which is the expected injection pressure to the gas network.

[65] This applies to the specific site analyzed: an offshore production farm located ~62 km to shore (Ijmuiden as a reference). Higher pressures may be required for production farms located further for shore.

In both analysed scenarios, the maximum gas flow rate (and therefore compressor duty) corresponds to all the electrolysers are producing at rated production, for which a single compressor could technically be used to handle the total capacity. However, after discussion with industry experts, it is decided to divide the compression service into two parallel compressors, each one handling half of the required flow rate capacity (and thus compression duty), and to have a spare unit (also sized to handle half of the required flow rate capacity). This decision is made for two main reasons. First, according to industry experts, reciprocating compressors have a turndown capability of around 30% of the rated capacity. Thus by having two units with half capacity in parallel, this operational point also decreases by half. Second, the use of two operating units with a spare helps ensure the availability of the compression system; the previous is due to if one of the compressors fails or needs to be taken off for maintenance, only half of the wind farm gas compression stops before the spare units take over

The Compressor Capex cost is calculated using a fitted engineering equation (see equation (6)) from hydrogen compressor costs obtained from internal TNO quoting and reported/provided industrial data (see Table 52 and Figure 53 in the appendix).

$$CAPEX_{comp}[M€] = 0.8238\ln(Power_{Compressor}) + 3.1574 \tag{6}$$

Where $Power_{Compressor}$[MW] is the compressor power

The operational cost of the compressor is assumed to be a function of the cost for running the compressor and a fixed maintenance cost as follows

$$OPEX_{comp}[€] = \left(A_0 \frac{t_{year}\, e}{\eta_{iso}\eta_m}\right)W \; + PF_{comp}\, CAPEX_{comp} \tag{7}$$

Where $A_0[-]$ is the availability of the compressor; $t_{year}\left[\frac{h}{year}\right]$ are the operating hours per year; $e\ \left[\frac{€}{kwh}\right]$ is the electricity cost; η_{iso} & η_m are the isentropic and mechanical efficiency of the compressor, respectively; $CAPEX_{Comp}$ is the compressor CAPEX, and PF_{comp} is the maintenance penalty factor of the capital cost (assumed 8 % of the capital cost from reference [70])

6.2.7 Hydrogen Pipeline

The hydrogen transport costs through the pipeline are considered only for the offshore electrolysis case. The pipeline transport model includes costs estimations for the transfer pipeline (hydrogen from a wind turbine to a centralized collection point) and the export pipeline (hydrogen from the collection point to shore). The installed pipeline cost is determined based on the pipeline's length and diameter using the engineering costs equation shown in equation (8). This equation was obtained from the estimated new hydrogen pipeline installed cost in the North Sea reported by DNV GL [9].

$$CAPEX_{Pipeline}[M€] = (0.0801\, D_{Pipe} + 0.2853) * L_{pipe} \tag{8}$$

Where D_{pipe}[in] is the pipeline diameter, and L [km] is the pipeline length

The resulting cost using equation (8) provides higher pipeline cost estimates than the typical pipeline cost models used in the literature [119, 120, 121]. However, this engineering cost equation was selected as it is the closest to the conditions operated in this project(transport of pressurized H_2 in the North Sea). A comparison of the DNV GL approach's resulting cost with other pipeline costs reported in the literature can be found in Figure 54 in the appendix.

The length of the export pipeline is assumed to be equivalent to the distance of the wind farm to shore (~62 km of IJmuiden Ver). On the other hand, the length of the transfer pipeline is determined assuming a rectangular-shaped wind farm in which all turbines in a row are connected to a single gas manifold that extends to the collection point in the vicinity of the wind farm. Therefore, the total transfer pipeline length is equivalent to the length of a single gas manifold multiplied by the number of rows in the wind farm layout.

The export/transfer pipeline diameter is determined based on the maximum allowed pressure drop in the pipeline resulting from the friction losses of a compressible gas (see equation (7) in the appendix). The maximum pressure drop is taken in the model as a design variable, which for the export pipeline was set to 20 bar (from the compressor output pressure of 100 bar) to fulfil the injection pressure in the gas network (80 bar). On the other hand, the maximum pressure drop for the transfer pipeline is set to 2 bar (from the electrolyzer output pressure of 30 bar), resulting in a modest pipeline diameter per manifold.

6.3 Results

6.3.1 Current 2020 LCOH

Figure 36 depicts the Levelized Cost of Hydrogen (LCOH) estimated for the two analysed scenarios when current (2020) electrolyzer cost and efficiency is utilised. The specific cost values can be found in Table 53 in Appendix D.

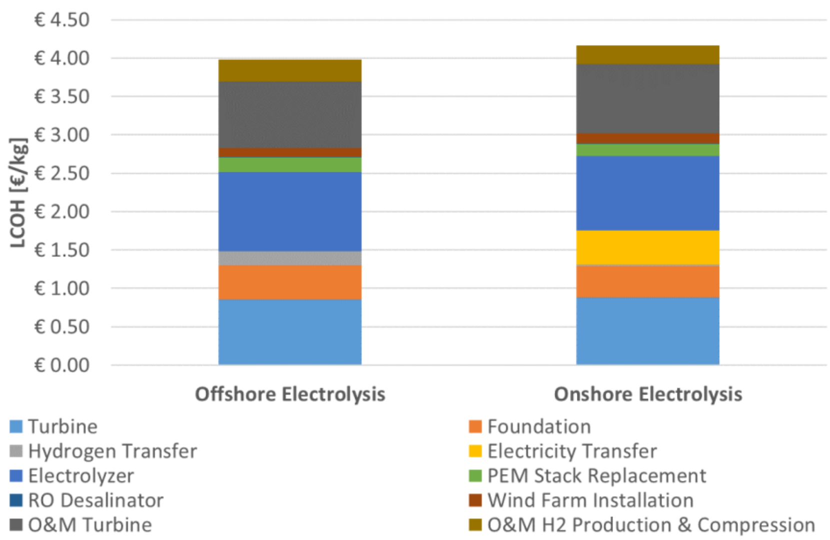

Figure 36 Estimated Levelized Cost of Hydrogen (LCOH) for Offshore (left) and Onshore (right) Electrolysis. PEM Electrolysis with 2020 Technology and Cost. Ref. Site Ijmuiden (62 km from shore) and 15 MW wind Turbine

The estimated LCOH for the offshore case results in a modest lower cost (~4 €/kg) when compared to the onshore one (~4.2 €/kg). The reason for this subtle difference can be explained as follows:

First, as shown in Figure 36, there is undoubtedly a cost-benefit in transferring energy in the form of hydrogen (grey bar) for the offshore case with respect to the form of electricity (yellow bar) in the onshore one. In this regard, the cost contribution of transferring energy is 0.18 €/kg and 0.48 €/kg for the offshore and onshore cases, respectively. However, although this benefit exists, the modest impact in the LCOH is due to energy transfer (either in the form of electricity or hydrogen) is due to this cost is not the main contributor to the total cost of hydrogen. Instead, in both cases, the predominant cost contributors to the LCOH are the turbine's and electrolyzer initial investments (dark and light blue bar, respectively) and the O&M cost of the turbine(dark grey bar).

Besides, it is also worth noting that the cost difference is for the wind farm characteristics established in Table 24; however, In the future, with larger wind farms farther from shore, the impact of the energy transfer will become more prevalent and thus, its impact on the LCOH.

Finally, part of the cost decrease gained from transporting hydrogen instead of electricity is hindered in the offshore case due to increased electrolyzer's Capex and Opex cost. These cost increases result from the marinization and O&M penalty factors to which an offshore electrolyzer system incurs.

On the other hand, in Figure 36 it can be seen that the H_2 production & compression O&M cost (brown bar), combined with the stack replacement (green bar) cost, are much smaller than the estimated turbine's O&M cost (dark grey).

The previous results can partially be explained from the assumptions taken in the economic model, in which the electrolyzer, compressor & desalination Opex cost are obtained as a component fraction of the respective equipment Capex. In particular, the contribution of the electrolyzer's yearly labour cost (~0,5% % initial Capex investment reported for the onshore) is relatively small (note that consumables were assumed to add a fixed extra cost of 1.5 % initial Capex investment to the electrolyzer's Opex). The small labour requirements are confirmed with electrolyzer vendors, which stated that this activity is, in current onshore electrolysis system's, mostly limited to visual inspections (that can be replaced by remote monitoring) and consumables exchanges (such as filters for the water purification module).

In the offshore case, performing activities such as exchanging a consumable will undoubtedly increase the O&M cost (included when applying offshore penalty factor), as additional factors, such as accessibility, logistics, and equipment use, are more costly; however, it is possible to engineer around some of this issues; for example, in the water purification module, spare filters that switch over automatically can be added to limit the number of visits offshore. In addition, offshore visits to the turbine can be combined with the current turbine's O&M activities to minimize the total O&M cost.

On the other hand, an issue that arises and cannot be captured by the simplified Opex approach used in this report is the potential increase in O&M costs resulting from unscheduled maintenance activities due to potential failures in the new equipment/systems added to the wind turbine. When a component fails, the O&M cost increases because the said component needs to be repaired/replaced. Failure of a component also impacts the LCOH as there are fewer operating hours for hydrogen production. Unfortunately, currently, there are no installed offshore electrolyzer systems that can be used as a reference to estimate the impact of failures on O&M cost. However, a non-extensive failures list for related equipment/systems operating in an offshore environment was built (see Table 54 in Appendix D), so future design stages have an insight into key components that need attention.

6.3.2 Electrolyser's Manufacturing & Technology Developments Impact

Figure 37 depicts the expected LCOH for the expected 2025 scenario in which more efficient PEM electrolysis (High Eff. In the figure) or/and PEM Capex cost reductions due to standardization and maker volume (std. in the figure) have been reached.

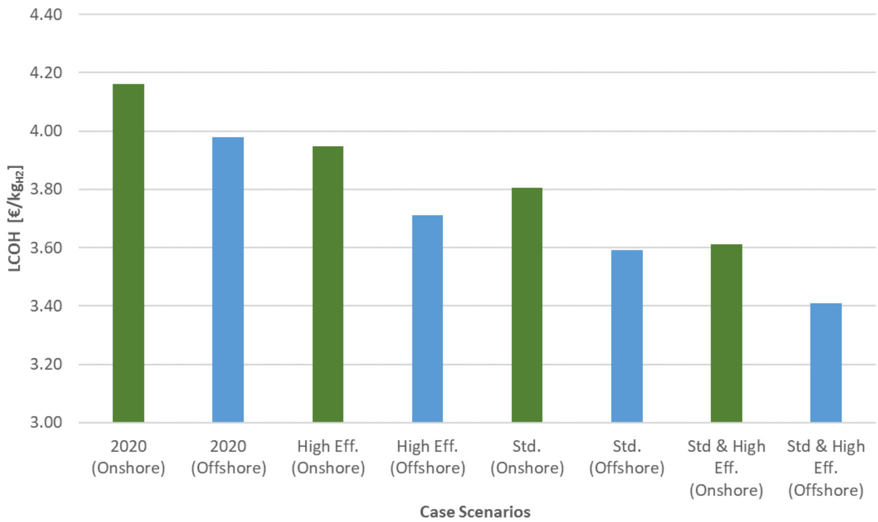

Figure 37 LCOH at Different Case Scenarios. High Eff: PEM Electrolysis Efficiency Improvements in a 2025 scenario; Std: Cost Reductions due to Standardization and Market Volume

Figure 37 shows that the offshore electrolysis case still results in a better LCOH when comparing all the assessed scenarios. Among the two potential paths to decrease the LCOH, cost reductions in the Capex of the electrolyzer (due to standardization and market volume) appear to have a slightly higher impact than the potential increase in inefficiencies (estimated for 2025) has.

When the potential cost reductions are combined, the LCOH for the offshore electrolysis reaches a minimum of ~3.4 €/kg, which is accounts for ~15% reduction compared to using current (2020) technology and cost. The estimated minimum LCOH is still not competitive with the current cost of grey hydrogen (<2€/kg at the point of consumption) for large-scale applications (such as refineries and fertilizer plants). However, the green hydrogen cost may be competitive with potential emerging markets, such as heavy-duty mobility, in which higher prices are expected (5-7€/kg at the point of consumption). It should be noted that the calculated LCOH does not incorporate costs that are incurred after the hydrogen is delivered to shore from the wind farm. Therefore, the LCOH is expected to be higher at the point of consumption.

6.3.3 Sensitivity Analysis

Figure 38 depicts the sensitivity analysis performed to assess the impact of the assumptions with major uncertainty into the Levelized Cost of Hydrogen (LCOH).

The first assumption tested was the impact of the marinization penalty factor that refers to extra cost on the Capex of electrolysis system due to potential modifications required for the system to withstand the harsh offshore environment. The base case for this item assumed a penalty factor of 15 % extra cost for the Capex of the electrolyser. For the sensitivity analysis, this penalty was varied ± 10% from the base case, corresponding to 5% and 25% marinization extra cost. The higher penalty is aligned with the estimated marinization cost by DNV [9]. In contrast, the lower end is an optimistic case considering that current electrolysis systems are containerized solutions in which the atmosphere is already conditioned.

The second main assumption was related to the cost resulting from modification in the transition piece to accommodate the electrolyser system. The base case assumed a penalty factor of 50% extra cost for the transition piece. For the sensitivity analysis, this penalty factor was varied ± 50% from the base case, corresponding to 20 to 80 % transition's piece extra cost, respectively.

Finally, the penalty factor that accounts for the extra cost of performing operations and maintenance offshore instead of onshore also has a large share of incertitude. This incertitude is due to no electrolyser plants being installed or operated offshore at the time of writing this thesis. The base case assumed 100 % extra O&M's labour cost than its onshore counterpart. For the sensitivity analysis, this penalty factor was varied ±50% from the base case, corresponding to 50 to 150 % of O&M's labour extra cost, respectively.

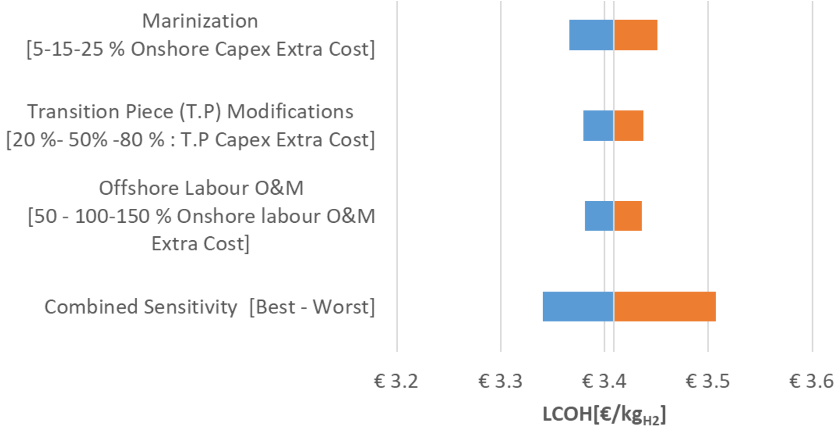

Figure 38 Sensitivity of Cost Penalty Factors Applied in the Economic Model. Future 2025 Scenario

As shown in Figure 38, the transition piece and the electrolyzer's offshore labour cost penalty factors have a relatively low impact on the LCOH. These results are expected due to the mentioned elements have a small cost contribution to the LCOH. On the other hand, the electrolyzer's marinization penalty factor has a higher impact on the LCOH with fewer variations(± 10%) than the other penalty factors (e.g. ± 30% for the transition piece), which is the result of the electrolyzer's Capex high cost contribution in the LCOH.

6.4 Summary of Findings

- There are economic gains of transporting energy in the form of hydrogen over electricity. However, this potential is hindered as energy transportation is currently not the main cost contributor to the LCOH. Instead, Capex & Opex of the wind turbine and the electrolyzer remain predominant cost contributors with current technology and prices.
- The estimated LCOH of offshore electrolysis today is estimated to be ~4 €/kg. However, a future scenario analysis in which PEM technology reaches higher efficiency and lower Capex cost can decrease the LCOH to 3.4 €/kg. This levelized cost is not competitive with grey hydrogen cost but opens the possibility to use green hydrogen in emerging markets like heavy-duty mobility.
- There is much incertitude on the real impact of the O&M cost of offshore electrolysis. Future economic analysis should address this issue.

7 Design Deliverables

The main objective of the PDEng project was to perform a conceptual design of an electrolyzer integrated with an offshore wind turbine for hydrogen production. The main design deliverables are the proposed concept, the documentation shown in this report, and the tools (or modification of tools) developed during the design process.

7.1 System Goals & Requirements

The system goals & requirements defined are revisited to verify their compliance during the design process.

Table 25 Requirement Validation

System Requirements		
Tag	**Description**	**Validation**
SR1	The system shall produce hydrogen from offshore wind energy	Refer to System Logical Architecture (Figure 16), System Sizing Estimations (Table 20) and System Concept (Figure 35)
SR2	The system shall operate decoupled from the electrical grid	Refer to Operational Flexibility Analysis (section 5.4) Potential operation issues of decoupled operation were analysed. The system is modularized, and buffer storage is proposed for low wind operation. Back-up requirements need further analysis.
SR3	The system shall deliver the produced hydrogen to an offshore collection point	Refer to H_2 Transfer & Compression (section 4.3.5) The produced H_2 has sufficient pressure (~30 bar) to be transferred to a centralized point at the vicinity of the wind farm. Then, further transfer to shore is performed using (dry) reciprocating compressors.
SR4	The system shall be designed for a "typical"* North Sea offshore environment conditions	Refer to Site Wind Characteristics (section 5.3) The system was designed based on IJmuiden site characteristics located at the North Sea.
SR5	The system shall operate unmanned	This design requirement is not explicitly addressed in a section. However, there are no systems within the design that need the continuous presence of operators. Manned intervention is required only to perform maintenance activities.
SR6	The system shall use PEM water electrolysis to produce hydrogen	Refer to electrolysis system logical architecture & process description (section 4.3.3), Technology Baseline (Table 17), and PEM Modelling (section 5.2) The PEM electrolysis system was analysed in deep during the system design. Technical assessments in terms of operational flexibility, physical & electrical integration were performed.
SR7	The system shall be designed for an operational lifetime of at least 20 years	Refer to Economic Analysis (Table 24) The economic analysis considered used an industry-grade tool (TNO Economic calculator) for O&M estimations. In addition, the expected operational lifetime of the project was considered to account for the electrolyzer replacements.
SR8	The Levelized Cost of Hydrogen (LCOH) of the integrated system shall be	Refer to Current 2020 LCOH (section 6.3.1)

Tag	Description	Validation/Notes
	competitive with the emerging heavy-duty mobility markets (< 5 €/kg)	The estimated LCOH for the integrated system is 4 €/kg under the assumptions performed in the economic analysis.
System Goals		
Tag	**Description**	**Validation/Notes**
SG1	The Levelized Cost of Hydrogen (LCOH) of the integrated system should be competitive with current fossil base methods of hydrogen production (<2€/kg)	This system goal was not fulfilled as the lowest LCOH was 3.4 €/kg. Further cost reductions and technological innovation than the estimated in this study are required to bring down the LCOH to the expected value.
SG2	The system should be able to be safely operated & maintained	Refer to Operational Flexibility Analysis (section 5.4) and Concept Selection (section 5.6.3) Safety was considered during the design process. However, a more rigorous analysis is required in further stages of design.

7.2 Design Reflection

As part of the Design methodology, a reflection is made on the design process. The reflection is performed in terms of functionality, constructability, realizability & impact according to the PDEng study Guide.

Functionality	The concept design & documentation in this report establish the basis for future stages of design. However, the design still needs more refinement and detailed analysis in safety, installation & maintenance aspects. The concept developed in this PDEng is bounded to the site conditions and technology assumptions made during the design process. However, the insights gained & methodology in this PDEng can be reused to design systems at different scales and contexts.
Construction	The design was structured hierarchically using logical architectures at different system levels. In addition, interfaces, operational compatibility, environmental conditions, installation impact, and synergies of the systems were considered.
Realisability	The system is designed using technology currently available in the market, and model-based analysis was performed to verify the technical feasibility of the design at a conceptual level. The economic analysis used industry-grade tools and current cost data to estimate the LCOH. However, significant assumptions were made to estimate the O&M cost for the offshore scenarios. These assumptions require further revision.
Impact	The technological design addressed in this PDEng offers a potential way to decarbonize the industry and contribute to the CO_2 emission reductions targets. However, the potential negative environmental impact of the technological design and mitigation measurements still need to be considered. Some of the impacts that can be considered are: hydrogen leakage, water brine disposal of the desalination, and material scarcity for the PEM electrolyzers In this report, potential safety risks for the integrated wind -electrolyzer system were analysed, and mitigation measures were proposed. However, a more in deep risk assessment and validation of the proposed measurements is required.

8 Conclusions & Recommendations

8.1 Conclusions

In this PDEng, the conceptual design of a PEM electrolyzer system integrated with a monopile-fixed 15 MW offshore wind turbine to produce 'green' hydrogen in the North Sea was developed. In the proposed concept, the electrolyzer, heat management, purification and desalination systems are integrated onto an enlarged external platform located at the transition piece of the turbine substructure.

The main conclusions of the design process are presented below.

Reverse osmosis was the selected technology for water desalination. This technology is advantageous in terms of reduced footprint and higher energy efficiency. However, due to its low flexibility, interfacing with the wind turbine-electrolysis system required the addition of a buffer tank to manage the fluctuations in water demand and power supply.

The pressure of the produced hydrogen in the turbine (~30 bar) is sufficient to transfer it to a centralized collection point in the vicinity of the wind farm. Therefore, to take advantage of economies of scale and liberate space in the wind turbine, it was chosen to perform centralized compression using (dry) reciprocating compressors.

The operational compatibility between the 15 MW offshore wind turbine and the electrolyzer system was analysed. The results of this analysis showed that the turbine's maximum power step changes expected when the 15 MW reference wind turbine operates in the IJmuiden site conditions (<1.5 %/s) and in a reference IEC Class B wind profile (< 9.7%/s), fall below the ramp rates capabilities (10%/s) of current industrial PEM electrolyzer systems.This implies that this electrolysis technology is suitable for direct connection with the turbine in terms of dynamic characteristics.

In addition, further analysis of the wind turbine-electrolyzer operational compatibility showed that a critical operational point occurs during low wind speed periods. In this period, the power supplied to the electrolyzer system (when assumed as a single unit) falls below the minimum safe operational threshold of the electrolyzer system. This issue can potentially be solved by modularising the electrolyzer system, which, when combined with a control strategy, reduces the minimum safe operational threshold. In this study, the electrolyzer system is suggested to be split into at least 3 modules, each with a 5 MW capacity.

The proposed level of modularization (3 modules) still showed potential safety risks when the integrated system operates near the turbine's cut-in wind speed. In this scenario, short-term (<100 s) power gaps that can potentially compromise the safe operation of the electrolyzer system also occur. In this study, it is suggested to add supercapacitors as a short-term buffer to handle this issue.

From the previous analysis, it is concluded that the offshore wind turbine and electrolyzer system can be integrated from an operational point of view. However, further operation validation at low wind speeds and near cut-in wind speed is still required in subsequent design stages.

The physical integration of the electrolyzer within the offshore wind turbine was also analysed. For this aim, material and energy flows were determined, and the sizes of the main systems required for the integration were estimated. During the system sizing estimations, some opportunities for footprint reduction, when compared to current onshore PEM electrolysis systems, were identified. In this regard, footprint reductions were obtained by using a compact seawater plate heat exchanger for the cooling system, scaling up the PEM module (especially the O_2 gas-liquid separator), moving the hydrogen purification step to a centralized collection point, and using high-frequency transformers for power conditioning.

The added mass of the complete electrolysis system was roughly estimated to be in the order of 300 tonnes. This mass was subjected to a natural frequency check, which showed that no impact is expected when the electrolyzer system is placed at the lower sections of the turbine structure (such as in the tower base or on/at the transition piece).

To reduce the complexity of the offshore installation process, this study recommends that the electrolyzer be combined with the transition piece onshore. The combined system would then be installed offshore as per traditional installation methods. The added weight is shown to be within the capabilities of the required transportation and lifting equipment.

Two integration options were proposed for the combined system: internally within the transition piece or on an enlarged external platform surrounding the transition piece. From a comparison of the two options, the external integration option was chosen due to fewer structural modifications, less complex maintenance logistics, lower difficulty of access, and lower perceived risk.

An economic assessment of two reference cases was performed: electrolysis offshore (integrated in the turbine) and electrolysis onshore. The assessment considered (among others) the current electrolyser's technology performance and costs, given a wind farm located 62 km from shore and, in both cases, that the produced hydrogen be delivered to a hydrogen gas network injection point located close to the shore. From this assessment, a LCOH of 4 €/kg and 4.2€/kg were estimated for the offshore and onshore cases, respectively.

An analysis of the cost contributors to the LCOH concluded that for the studied cases, the cost contribution of transferring the hydrogen produced offshore (0.18 €/kg) is lower than the cost contribution of first transferring electricity to shore and then converting it to hydrogen (0.48 €/kg). At present, however, this cost-benefit in transportation is hindered due to the high CAPEX and OPEX cost contributions of the electrolyzer and the wind turbine.

Based on an economic assessment of a future 2025 scenario in which CAPEX cost reductions (due to mass production) and efficiency improvements of the electrolyzer system have been reached, The LCOH resulted in a minimum of 3.4 €/kg for the offshore case. This levelized cost is still not competitive with the current cost level of grey hydrogen (<2€/kg) but already opens the possibility of using green hydrogen on emerging markets, such as long-haul vehicles in which higher prices (5-7€/kg at the point of consumption) can be expected.

The main conclusion of the design process is that integration of the electrolyser system is technically possible with existing technologies, and no technical limitations were found at this stage of development. From an economic point of view, the LCOH of green hydrogen is, at the moment, still higher than the grey one. However, the integration of offshore wind and electrolysis, combined with modest innovations in the 2025 scenario, offers the possibility of closing this gap more and more. Moreover, the market and the need for more sustainable ways of producing hydrogen and decarbonizing the industry exist today. Thus, it is just a matter of time before green hydrogen becomes the dominant type of hydrogen in our society.

8.2 Recommendations

In this project, the degradation of the electrolyzer system was assumed to be proportional to its operating hours. However, further research is needed on the impact of continuous wind power fluctuation and intermittent operation on the electrolyser system's lifespan. In this regard, accelerated test cycles could be performed using high resolution (e.g. in seconds) power production profiles of individual turbines, like those used in this project.

As mentioned in the conclusions, critical operational points for integrating the wind turbine with the electrolyzer system occurs at low wind periods. Therefore, further research is recommended, especially on the control strategy and the potential impact of the modular operation on the electrolyzer system lifespan.

The analysis of the weight impact considered only a natural frequency check and additional requirements in terms of installation & maintenance. However, much more research is needed on installation, operation, and maintenance aspects such as procedures, tools, Health Safety & Environment (HSE), among others.

During the economic analysis, due to the limited literature and industry information, several assumptions were made to determine the LCOH in the offshore case. In particular, electrolyser system O&M and PEM stack replacement cost estimations were based on cost figures reported for onshore systems and assumed penalty factors. This approach resulted in large uncertainties in the estimated LCOH. Therefore, the offshore O&M cost still needs to be refined. Data collection for this aim can be part of the focus of incoming offshore pilot projects with electrolyzer systems.

Flexibility & maintenance drawbacks of a reverse osmosis desalination system were assumed to be handled using buffer tank and maintenance strategies. Further validation of the assumptions needs to be performed. In case that these strategies are found to not be sufficient in future stages of design, it is worth exploring mechanical vapour compression as an alternative desalination technology.

Finally, in this study, a potential electrical topology for the electrical integration of the electrolyzer system and the turbine generator was suggested. Further validation of this topology, or an exploration of alternative topologies, is recommended.

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APPENDICES

Appendix A Complement Methodology

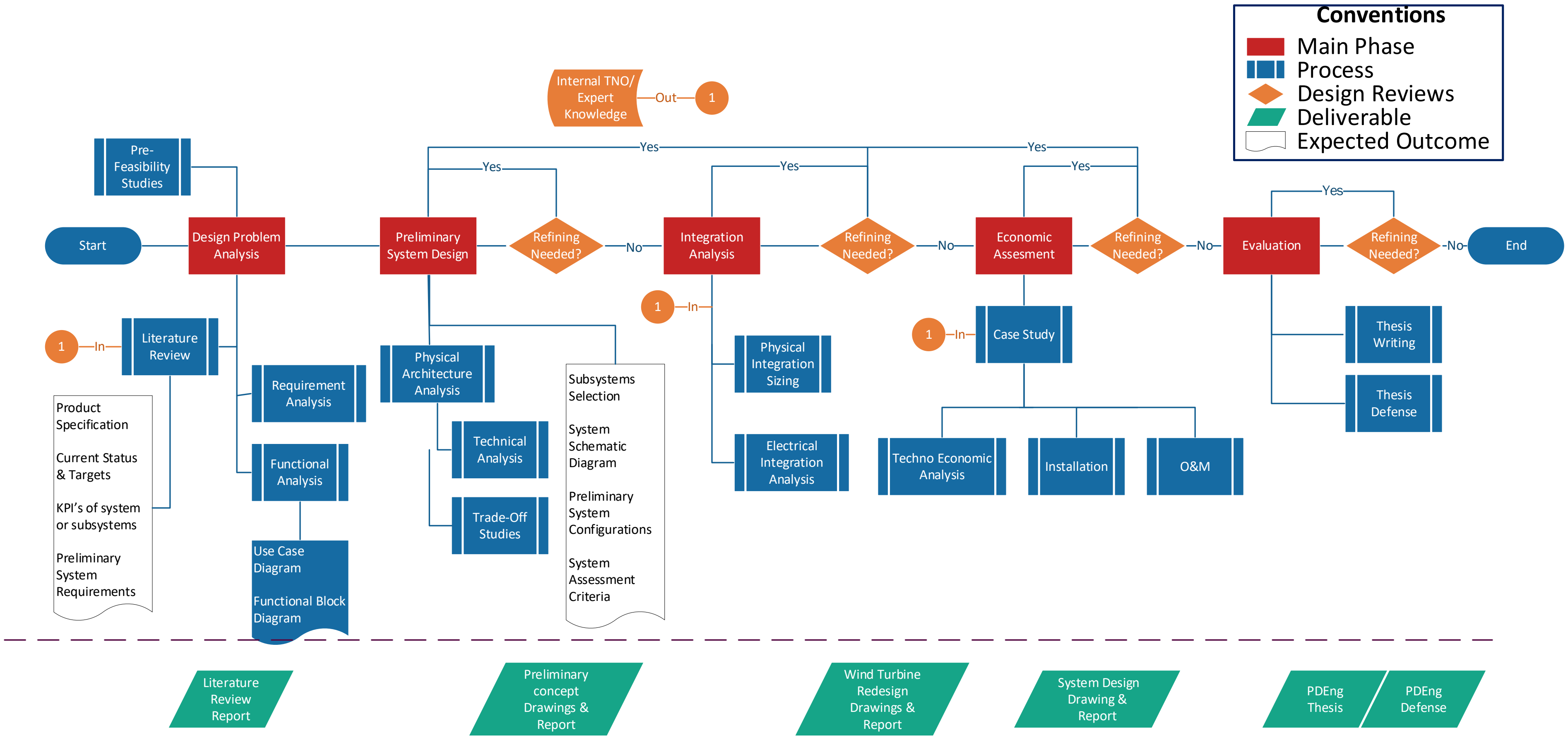

Figure 39 Extended Design Methodology

Appendix B Complement Preliminary Analysis

Appendix B.1 Functional Analysis

Hydrogen Electrolysis Functional Architecture

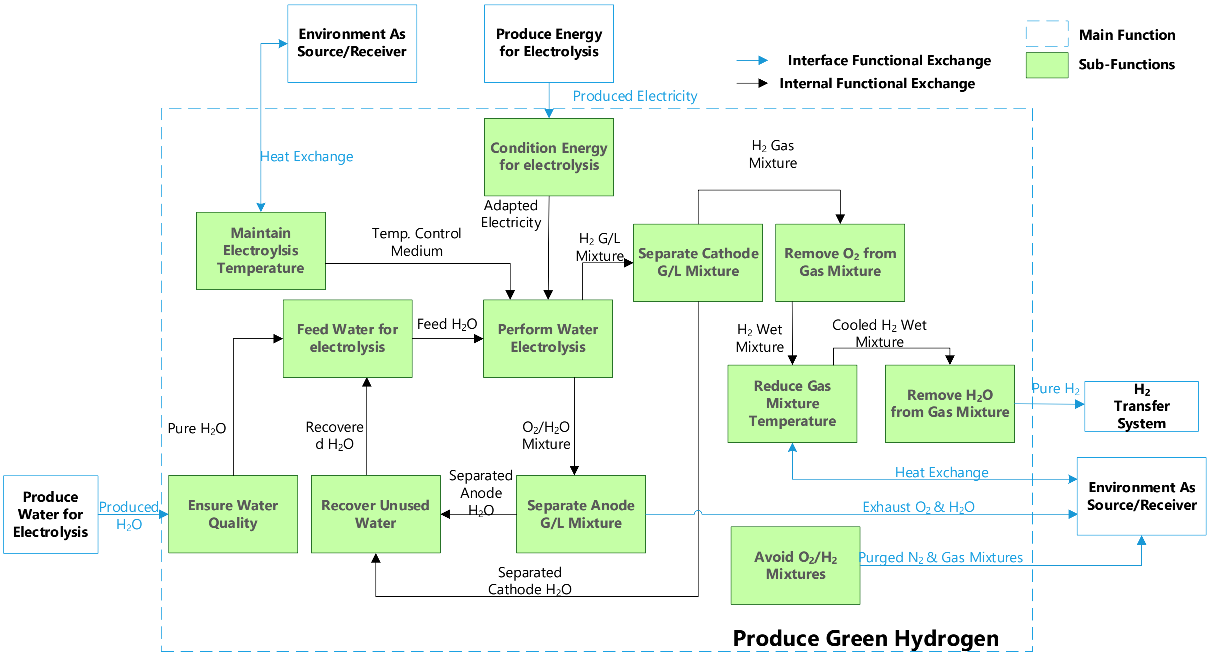

Figure 40 Hydrogen Electrolysis Functional Decomposition

Water Desalination Functional Architecture

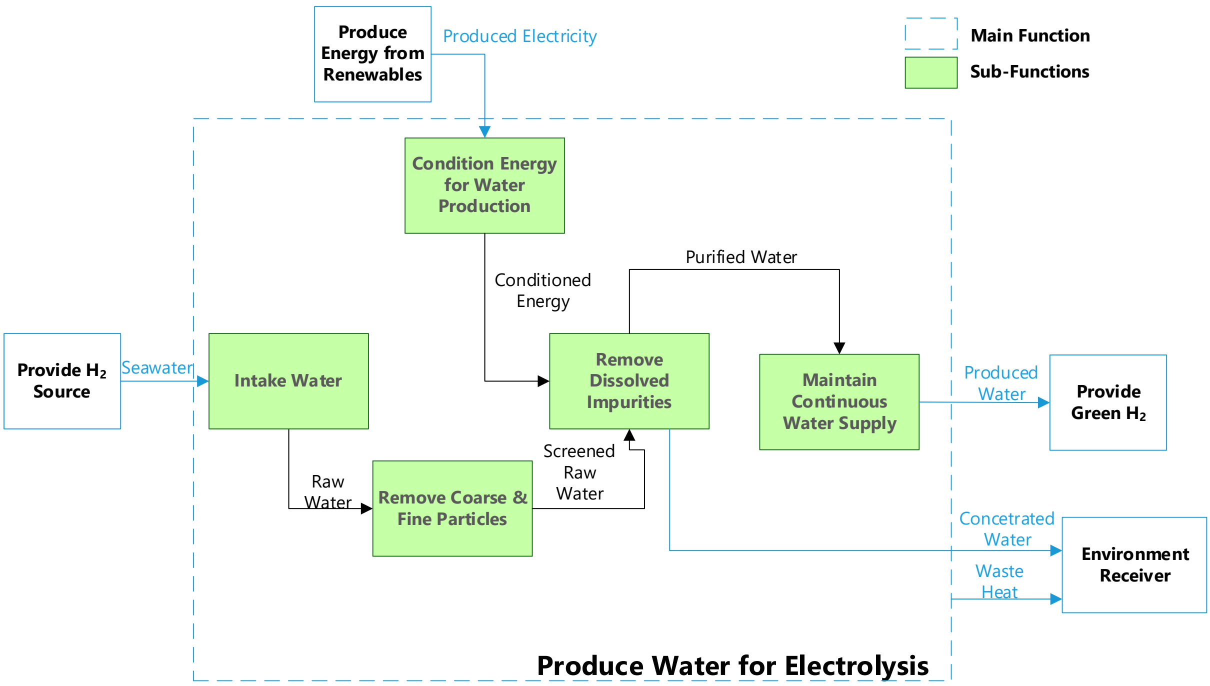

Figure 41 Water Desalination Functional Analysis

Appendix B.2 Reference Wind Turbine

Table 26 IEA 15 MW Offshore Turbine Characteristics. Reproduced from [58]

Parameter	Units	Value
Power Rating	MW	15
Turbine Class	-	IEC Class 1B
Specific Rating	W/m^2	332
Rotor Orientation	-	Upwind
Number of Blades	-	3
Control	-	Variable Speed/Collective Pitch
Cut-in Wind Speed	m/s	3
Rated Wind Speed	m/s	10.59
Cut-out wind Speed	m/s	25
Design Tip Speed Ratio	-	9
Minimum rotor Speed	rpm	5
Maximum Rotor Speed	rpm	7.56
Maximum Tip Speed	rpm	95
Rotor Diameter	m	240
Airfoil Series	m	FFA-W3
Hub Height	m	150
Hub Diameter	m	7.94
Hub Overhang	m	11.35
Rotor Precone Angle	deg	-4
Blade Prebend	m	4
Blade Mass	t	65
Drivetrain	-	Direct Drive
Shaft Tilt Angle	deg	6
Rotor Nacelle Assembly Mass	t	1017
Transition Piece Height	m	15
Monopile Embedment Depth	m	45
Monopile Base Diameter	m	10
Tower Mass	t	860
Monopile Mass	t	1318

Appendix B.3 Water Desalination Technology Selection

Water Desalination Processes

Below a brief description of the different water desalination technologies is given. Besides, Table 27 provides a summary of the main characteristics of these technologies.

Reverse Osmosis (RO)

RO is one of the most extended methods used today to desalinate water. In this method, a pressure higher than the osmotic pressure of seawater is applied in a membrane assembly. As a result, water flows in the reverse direction to the natural flow of the membrane [61]. These membranes are very sensitive to both biological and non-biological fouling. Therefore, careful pre-treatment of the water feed is necessary before entering the membrane assembly [122]. RO is one of the most efficient desalination methods in terms of electrical energy consumption when no external source of heat is available.

Multistage Flash (MSF)

In this process, flash evaporation of saltwater is performed in multiple stages. Each stages operating at a lower pressure than its predecessor, to support the flashing operation. This desalination process is relatively simple, which in turns make it easily scalable. The saltwater needs to be preheated, and a temperature source (typically steam) is required for operation. Note that electrical demand is also required to run the feeding pumps and pressure control. Besides, it has been reported that precise pressure levels are required in the different stages [60]. Therefore, some transient time is required to establish the normal running operation of the plant. This could difficult the application of this technology in a variable energy input context, such as operating with an offshore wind turbine.

Multi Effect Distillation (MED)

This process consists of utilising a sequence of consecutive condensation/evaporation process which are in decreasing order of temperatures and pressures. The first effect evaporates the process water by using and external heat supply. The steam produced inside the one effect is consumed as the energy source of the subsequent effect, so, whereas on one side, the entering steam is condensing, on the other side, the process water is boiling, and thus generating extra steam. This practice continues in every effect [123]. According to [60], this process is suitable for variable input application as the levels of operating temperature and pressure equilibrium are less critical. As the heat source is only used once, the risk of scale is minimized without requiring chemical dosing. Typical purity of this product contains less than 5 ppm TDS.

Mechanical Vapor Compression (MVC)

In a mechanical vapor compression plant, heat from a later stage of the process is compressed into a mechanical compressor to raise the saturation temperature of the steam. The higher temperature steam is passed through a heat exchange in which the thermal energy is used to vaporize new process water [123]. The main potential disadvantage of this process is that a compressor is used for the operation. This equipment represents the major energy input to the system [60].

Technology Characteristics

Table 27 Characteristics of seawater treatment technologies. Adapted from [61, 62, 124, 125]

Parameter/Technology	MSF	MED			RO
		Single	TVC	MVC	
Typical Unit Size $[x10^{-3}\ m^3/day]$	50-70	2.5-68	50-100	<5	0.01-128
Electrical Energy Consumption $[KWh/m^3]$	4-6	1.5-2.5	1-2.5	8-15	3-7
Thermal Energy Consumption $[MJ_{therm}/m^3]$	190-390	145-230	180-290	N/A	N/A
Electrical Equivalent for Thermal Energy $[KWh_{elect}/m^3]$	9.5-19.5	5-8.5	9.5-25.5	N/A	N/A
Total Equivalent Electricity Consumption $[KWh/m^3]^*$	15-25	6.5-11	16-26.5	8-15	3-7
Energy source [-]	MP ST	LLP ST/HW	LP/MP ST	Elect.	Elect.
Operating Temp. (°C)	90-110	60-90	60-90	~<70	<35
Output Purity (ppm)	2-5	2-5	2-5	2-5	<500**

MSF: Multi-Stage Flash; MED: Multiple Effect Distillation; TVC: Thermal Vapor Compression; MVC: Mechanical Vapor Compression; RO: Reverse Osmosis;
LLP ST: Low Low-pressure steam; LP/MP ST Low pressure/medium pressure steam;
HW: Hot Water; Elect.: Electricity; N/A: Not Applicable
*Assuming a fossil-based electricity production system at 30% efficiency
** Single-pass; Secondary pass can be added to reach 5-10 ppm

Multicriteria Analysis

Normalized parameters for the selection of the water desalination technology.

Table 28 MCA Normalized Results: Water Desalination

Normalized Values				
Criterion	**MSF**	**MED**	**MVC**	**RO**
Footprint [-]	0.20	0.25	0.21	0.33
Weight [-]	0.31	0.47	0.10	0.12
Flexibility [-]	0.17	0.17	0.20	0.45
Energy Needs [-]	0.17	0.26	0.39	0.17
Maintenance & Complexity [-]	0.25	0.30	0.25	0.20
Score	0.20	0.26	0.27	0.27

Market Screening

Table 29 Water Desalination Manufacturers Screening

Technology	Input	Output [ppm]	Production [m^3/d]	Weight [Kg]	LxWxH [m]	Heat source [-]	Op. Temp. [°C]	Manufacturer
RO	35000	<500	45	1678	4x1,8x1,6	NA	5-35	Searecovery
			85	1814	4x1,8x1,6		5-36	Searecovery
	42000		120	-	7x1,3x2,1		-	Cullligan
			960	-	7x2,2x2,2		-	Cullligan
	35000		12	350	0,8x0,8x2		5-35	Hatenboer
			30	860	1,5x1x2		5-35	Hatenboer
			100	2500	2,8x1,7x2		-	Hatenboer
		200	500	9500	6,1x2,4x2,9		5-25	Wartsila
	41000	-	1000	78000	12x7x2,62		15-32	IDE Tech.
			2000	133000	12,3x7,5x3,1			IDE Tech.
			5000	275000	24x7x2,5			IDE Tech.
MSF	Unsensitive	< 4	1500	-	12x3,9x4	Steam/ Waste Heat	>80	Wartsila
MED	Unsensitive	<2	18	660	1,3x1x1,7	Waste Heat	>70	Wartsila
MED	Unsensitive	<5	117	7500	2.8x1.9x2.6	Waste Heat	65	Wartsila
MED	Unsensitive	<2	80	833	1.7x0.9x1.4	Waste Heat	70-90	Alfalaval
MED	Unsensitive	<2	35	1050	2,3x0,9x1,4	Waste Heat	>70	Alfalaval
MVC	Unsensitive	<5	50	3700	2.5x2.2x2.4	NA	-	Alfalaval
MVC	Unsensitive	<5	70	4000	2.8x2.2x2.4	NA	-	Alfalaval
MED	Unsensitive	<5	30	2080	1,5x2,1x1,85	Waste Heat	>65	Alfalaval

RO: Reverse Osmosis ; MSF: Multistage Flash Distillation; MED: Multieffect Distillation; MVC: Mechanical Vapour Compression

Appendix B.4 Compression Technology Selection

Hydrogen Compression Technologies

Below a brief description of the different compression technologies is given. Besides, Table 30 provides a summary of the main characteristics of these technologies.

Reciprocating Piston

A reciprocating compressor is a positive displacement machine that throught the back and forth movement (referred as reciprocating) of a piston inside a cylinder increases the pressure of a gas. The operating principle of this machine is to generate an increase of pressure by reducing the volume that a gas occupies.

Reciprocating compressors are a mature technology used in several process in the industry. Oil lubricated compressors are a typical type of compressors used. However, the problem with oil lubricated compressors is that part of the oil can be carry over by the hydrogen gas, which results in product contamination. Therefore, in applications in which product contamination should be avoided (such as fuel cell applications) non-lubricated (also known as dry) compressors are preferred.

Diaphragm Compression

Diaphragm compressor is a type of mechanical compression that relies in a similar principle than reciprocating compressors. However, in this case, between the gas and the piston there is a diaphgram and oil. The movement of the piston pushes the oil, which causes elastic deformation of the diaphragm. This elastic deformation decreases the volumen of the gas in the cylinder resulting in a increase of pressure.

Ionic Liquid Compressor

This compressor also follows a similar operating principle than reciprocating compressors. However, in this case, the gas is compressed by the back and forth movement of an ionic liquid column (instead of a piston). The main properties of the ionic liquid is that it has very low vapour pressure and than hydrogen is insoluble in this component. The aforementioned properties allows the remotion of bearing and sealings which in turns reduce the complexity of this system compared to piston based reciprocating compressors.

Metal Hydride Compressor

In this system, low pressure hydrogen gas enters a vessel with a metal powder. In this vessel, hydrogen splits on the surface of the metal, forming atomic hydrogen, which gets absorbed inside the lattice structure of the metal. The absorption of hydrogen is an exothermic process, and therefore cooling is required to ensure sufficient hydrogen can be absorbed. After enough hydrogen is inside the lattice structure, the vessel is heated up again, releasing the hydrogen at a much higher pressure.

Electrochemical Hydrogen Compressor

This compressors are machines that are based on electrochemical principle to compress hydrogen. In this case, a difference of potential (supply electricity) is applied in a electrochemical cell where hydrogen gas is split into hydrogen protons at the anode side of the cell. The hydrogen protons are transported through a proton exchange membrane (PEM), from the anode to the cathode side of the cell. At the cathode side the hydrogen gets recombined to form new hydrogen molecules in which the electricity is converted in chemical potential which in turns increases the pressure of the hydrogen.

Table 30 Compressor Technologies Characteristics [75, 77, 78, 74]

Parameter/ Technology	Mechanical				Non-Mechanical	
	Recip. Piston (Oil-Free)	Diaphragm	Ionic Liquid	Centrifugal	EHC	Metal Hydride
Typical Flow Rate [Kg/h (Nm^3h^{-1})]	300-7000[a] (3000-75000)	<52 (<580)	<68 (760)	<18000 (<200000)	0.45-5 [b] (5-56)	0.36-1.1 [b] (4-12)
P_{out} [bar]	65-450[c]	500	<700	~100*	<900	<250
Energy Source [-]	Elect.	Elect.	Elect.	Elect.	Elect.	Heating (@ 90 °C) Cooling (@ 20 °C)
Efficiency [%]	>65%***	65-85	~90 %	-	~80%	~10% (thermal)
Energy [d] [Kwh/Kg_{H2}]	~5	~5	~3	-	~4**	10 (thermal)

[a] For upper limit flow rate, discharge pressures < 100 bar in a single unit are currently possible in oil free piston compressors.

[b] Several modules can be used to increase the flow rate output

[c] Oil free compressor are currently limited to a pressure output < ~450 bar.

[d] Compression from 0.7 to 25 MPa

*estimated from refinery hydrogen compressors

** Hyet reports: 8.7 kwh/Kg_{H2} @ 900 Bar, current developments are expected to decrease the energy to ~4 kwh/Kg_{H2}

EHC: Electrochemical Hydrogen Compressor

Multicriteria Analysis

Table 31 Normalized Results: Compression

Normalized Values					
Criterion	Reciprocating (Oil Free)	Diaphragm	Ionic Liquid	EHC	M. Hydride
Footprint [-]	0.68	0.20	0.10	0.01	0.004
Weight [-]	0.91	0.02	0.04	0.01	0.01
Flexibility [-]	0.3	0.1	0.3	0.3	0.1
Energy Needs [-]	0.2	0.2	0.1	0.1	0.4
Maintenance & Complexity [-]	0.1	0.1	0.2	0.3	0.3
Technology Readiness [-]	0.3	0.3	0.1	0.1	0.1
Normalized Score	0.39	0.16	0.16	0.15	0.14

Market Screening

Table 32 Compression Market Screening

Technology	Input [bar]	P_{out} [bar]	Capacity [Kg/h]	Weight [Kg]	LxWxH [m]	Energy Type [-]
Mech. Piston	40	270	14696	180000	35x30x8	Electricity
	30	70	16720	270000	25x16	Electricity
	10-100	100	101	1680	2,4x1,4x1,3	Electricity
	28-200	200	65	1680	2,4x1,4x1,3	Electricity
Metal Hydride	>10	250	1.1	-	-	Heat (90-150 °C)
			0.09	65	0,9x0,5x0,5	Heat (90-150 °C)
Ionic Liquid	5-200	700	66	17000	4,2x2,7x2,6	Electricity
Diaphragm	28	97	43	-	-	Electricity
	30	500	42	-	4.6x2.43	Electricity
	10- 40.	450	123	-	7,6x5x3	Electricity
	30	450	550	-	6x11x5	Electricity
Electrochemical	3-200	0-900	0.4	750	1.5x0.9x2	Electricity
	3-200	0-950	5	5000	3x2.5x2.6	Electricity
	0.35-13	20-200	0.03	-	1.3x0.76x0.7	Electricity

Centralized Vs Decentralized Compression

Figure 42 shows the assumed location of the centralized compression station. Note that the figure is only for visualization, spacing between turbines is not a scale.

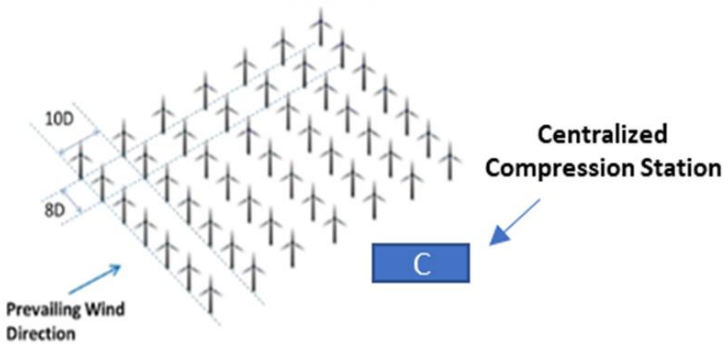

Figure 42 Location of a centralized compression system & wind farm array. Adapted from NREL

Table 33, shows the main assumptions made for the pressure drop calculations for the hydrogen transported via pipeline from the turbine to the centralized collection point (compression station).

Table 33 Assumptions for Pressure losses H_2 From Turbine to a Centralized Collection Point

Parameter	Value
Turbine Power [MW]	15
Rotor Diameter [m]	240
$m_{flow-H2}$**[kg/h]**	275
Turbine Spacing [-]	10 rotor diameters (D) in prevailing wind direction. 8 D in the perpendicular direction
Turbines per row	8
Turbines per group	6
Distance to Collection point [km]	25
Pressure Losses [Bar]	<1.5 bar

Appendix C Complement System Integration Analysis

Appendix C.1 Wind Profiles

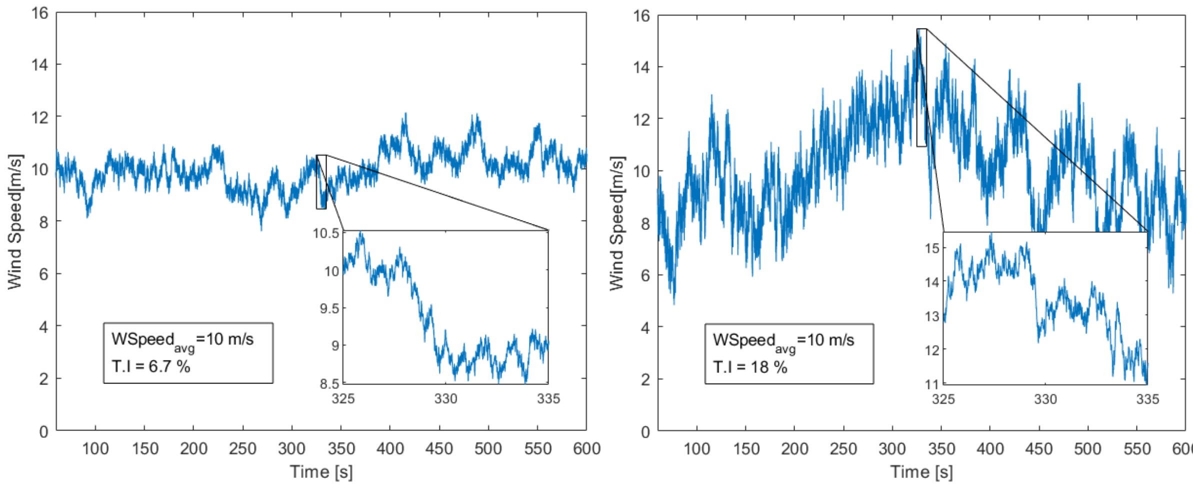

Figure 43 Generated Wind Speed time series for Ijmuiden Site (left) & IEC Class B (right) wind type at 10 m/s

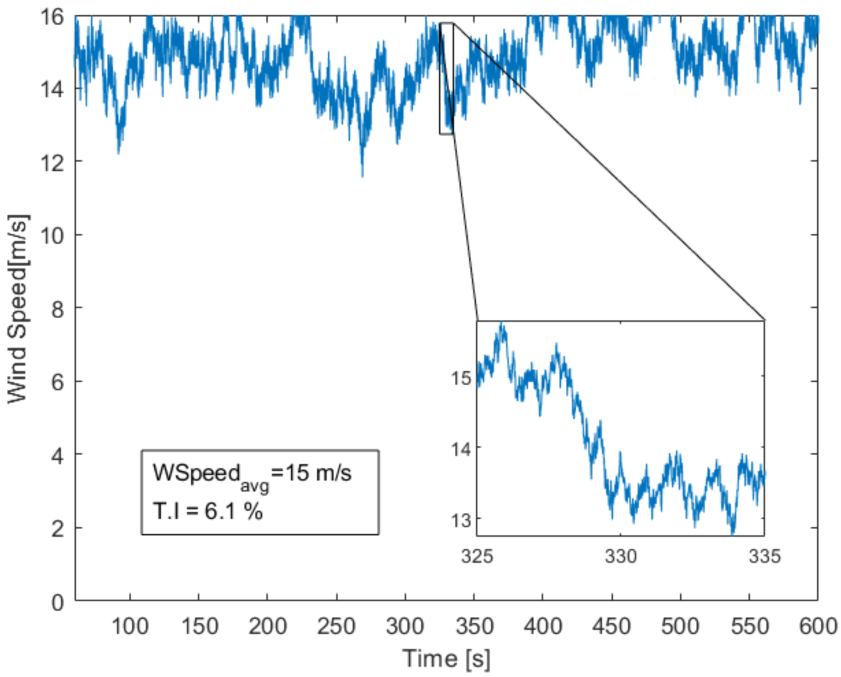

Figure 44 Generated Wind Speed time series for Ijmuiden Site wind type at 15 m/s

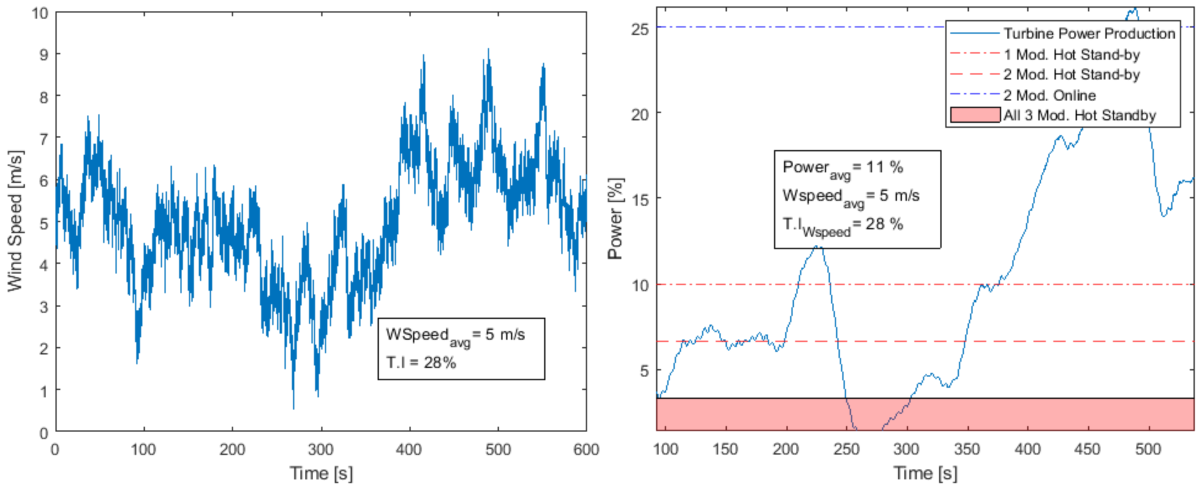

Figure 45 Wind(left) & Power (right) time series for a IEC class B at 5 m/s average wind speed

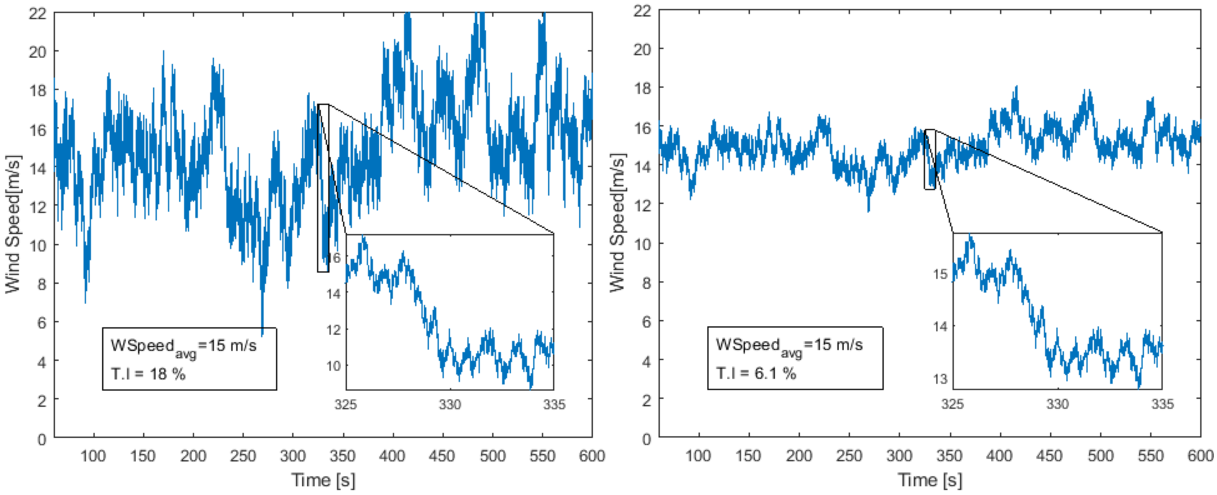

Figure 46 Wind Speed time series for (Ijmuiden Site) & IEC Class B type

Appendix C.2 Energy Storage Technologies Performances

Figure 47 shows the performance characteristics of several storage technologies.

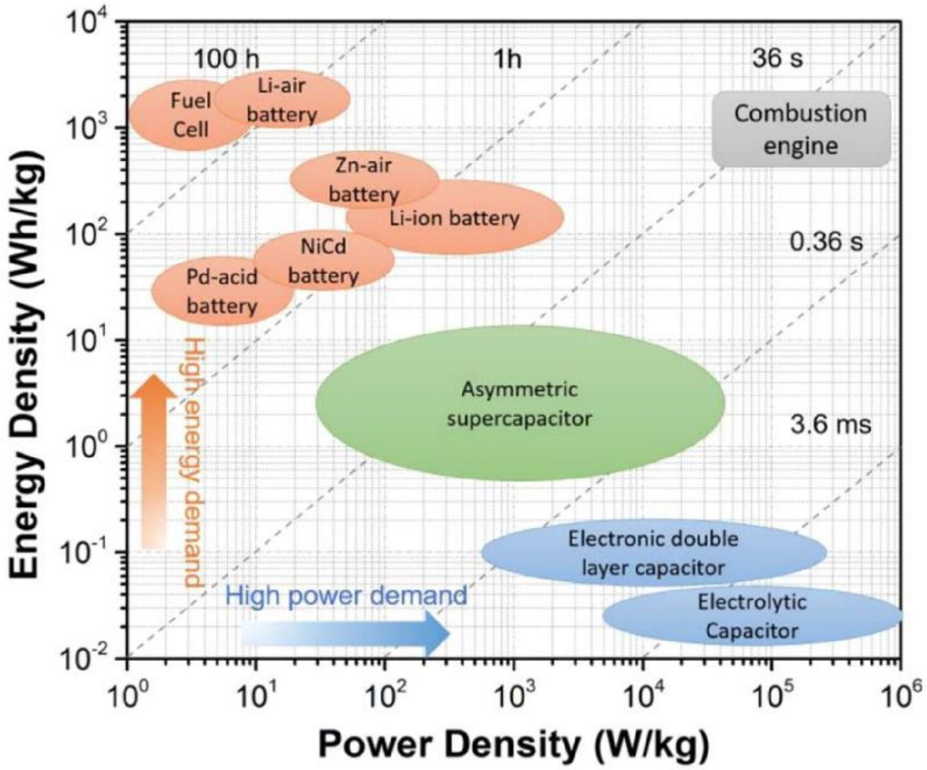

Figure 47 Energy Storage Technologies Performance. Reproduced from [126]

Appendix C.3 Electrochemical Modelling

General Electrolysis Model

The equilibrium electrical potential is obtained from the Nerst equation as:

$$V_{eq}[V] = V_{rev}^{0} - \frac{RT}{zF}\ln\left(\frac{a_{H_2O}}{a_{H_2}a_{O_2}^{1/2}}\right) \tag{9}$$

The activation overpotential is calculated from the Buttler-Volmer equations

$$V_{act,j}\,[V] = \frac{RT}{\alpha_j\, F}\, arc\, sinh\left(\frac{i}{2\, i_{0,j}}\right) \tag{10}$$

Where the subfix j is either for the cathode or the anode, $R\left[\frac{J}{mol\,K}\right]$ is the gas constant, $T[K]$ is the temperature, $F\left[\frac{C}{mol}\right]$ is the Faraday constant, $i[A/cm^2]$ is the current density and $i_{0,j}\left[\frac{A}{cm^2}\right]$ is the cathode/anode exchange current density and $\alpha_j\,[-]$ is the cathode/anode charge transfer coefficients

The exchange current density ($i_{0,j}$) is determined as:

$$i_{0,j}\left[\frac{A}{cm^2}\right] = \varphi_i\,\gamma_i\,\chi_i\,(1-\alpha_{gas})\,i_{0,ref} \tag{11}$$

Where φ_i is the fraction of catalyst effectively in contact with the ionomer and electrode, γ_i is the catalyst surface roughness, χ_i is the relative catalyst activity, α_{gas} is the oxygen coverage, and $i_{0,ref}$ is the reference current density.

The surface roughness is determined as:

$$\gamma_i = m_M\frac{6}{\rho_M d_M} \tag{12}$$

Where $m_M\left[\frac{Kg}{m^2}\right]$ is the catalyst loading, $d_M\,[m^2]$ is the average catalyst crystalline diameter, $\rho_M\left[\frac{kg}{m^3}\right]$ is the catalyst density

Voltages losses due to mass transfer were not included in the electrolyzer modeling as at the current densities assumed for the design process (< 2.5 A/cm^2) the effect of this phenomena is expected to be minimal and therfore is neglected. The parameters, used during the modelling are shown in the following subsection

Electrochemical Model Parameters

Parameters used for current (2020) performance curve in the electrochemical model and expected future (2025) scenarios are shown in Table 34 below.

Table 34 Electrochemical Model current & 2025 Estimated Parameters.

Model Parameter	2020	2025	Reasoning
Operating Temperature T_{ops} [C]	55	70	Faster degradation after 70 C. Higher T conflict with electrolyzer lifetime. Recent developments by NEL point to membranes that are resistant at these temperatures.
Anode Catalyst Loading $C_{Anode,Load}$ [mg/cm^2]	2	0,5	Medium to low relative impact. Recent, high efforts in the industry due to material scarcity
Membrane Thickness t_{memb} [µm]	178	125	Aligned with recent innovation efforts. Limited by crossover H_2 crossover at low loads.
Membrane Conductivity σ_{mem} [S/cm]	0.14	0.15 (+5%)	Limitations on material improvement to maintain membrane properties
Catalyst Utilization ϕi [-]	0.75	0.825 (+10%)	No significant changes in MEA architecture or manufacturing methods, such as (CCM).
Anode Catalyst Activity Factor X_{anode} [-]	1	1.2	Expected improvements in anode's catalyst performance.
Cathode Catalyst Activity Factor $X_{cathode}$ [-]	1	1.5	Expected improvements in cathode's catalyst performance. Relatively low impact
Oxygen coverage α_{O2} [%]	50	40	No significant changes in MEA architecture are expected to attain a much lower catalyst coverage.

Fitting Performance Model

Figure 48 shows the fitting results of the electrochemical model with respect to reported PEM electrolysis performance data reported in the literature.

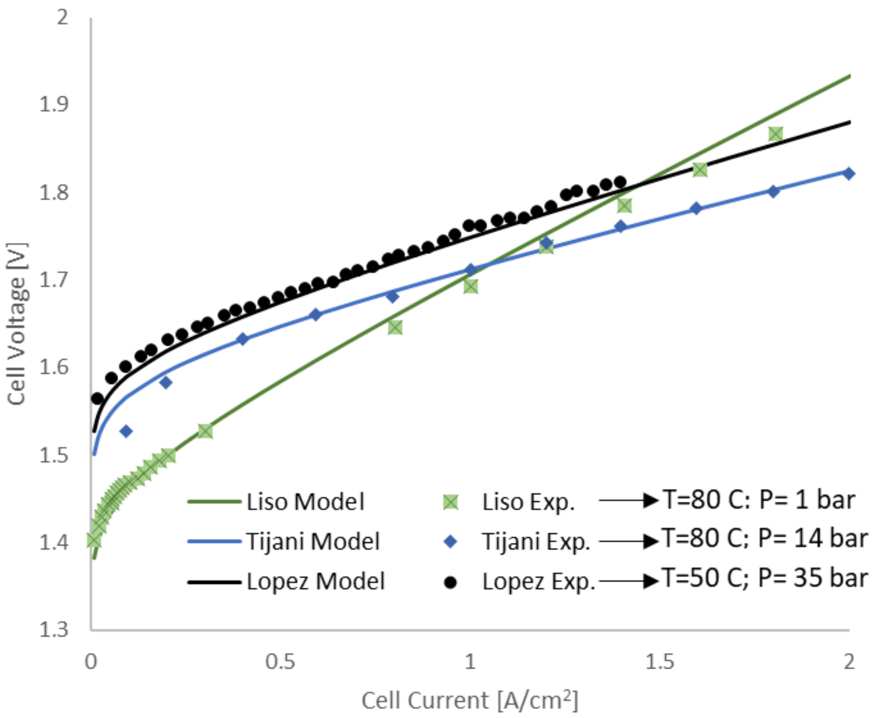

Figure 48 Electrochemical Model vs Experimental Data [91, 92, 93]

PEM Industrial Ramping Rates

Figure 35, shows reported ramping rates for current industrial size PEM electrolysis systems at different capacities.

Table 35 Industrial PEM Electrolyzers Ramping Rates

Reference	*Capacity [MW]*	*Ramping Time (%/s)*	*Notes*
Silyzer 300	*17.5*	*10 (Hot)*	*Primary Frequency Reserve Service Enable* [86]
NEL	*1*	*10 (Hot)*	*Full ramp up/down (cold) reported to be below 5 min*
EnergyPark Mainz Silyzer 200	*6*	*1.5 (Cold)* *3 (Hot)*	*Faster response times in a load range of 0-65%* [87]
HyBalance Cummins	*1.2*	*10 (cold)* *50 (hot)*	*Approved by Danish Grid operator as bidder in electricity market* [88]

Appendix C.4 Energy Distribution at higher pressures

Figure 49 shows the estimated energy distribution of the wind when the produced hydrogen is compressed from ~ 30 bars up to 400 bars.

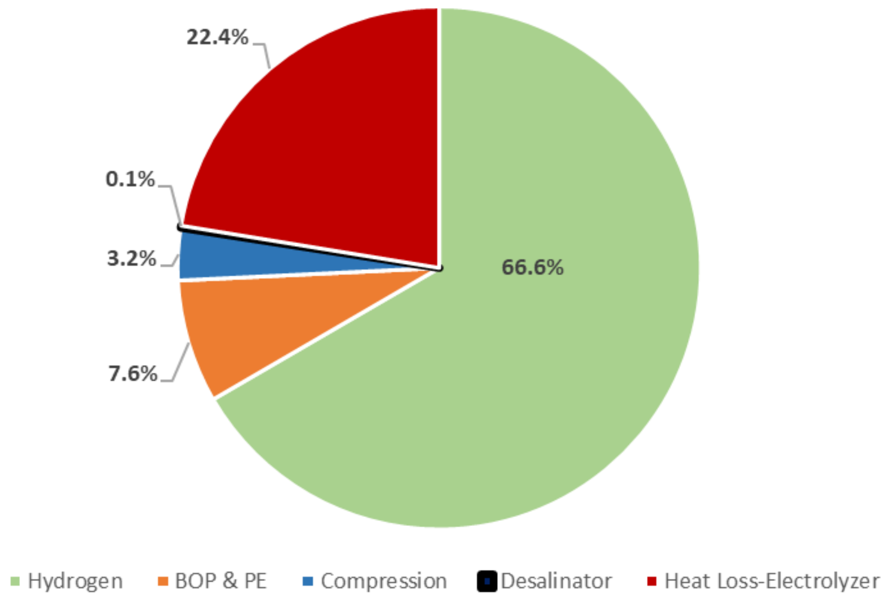

Figure 49 System Energy Distribution at BOL (Left) & EOL (Right). Assumed H_2 transmission pressure of 400 bar

Appendix C.5 Electrolysis Process Mass Balances

Table 36 Electrolyser 5 MW Module Complete Mass Balances @ BOL

5 MW Module @ BOL - Operation Mode: Full Load										
Stream Name	**D. H_2O Supply**	**Conditioned H_2O**	**H_2O Recycle**	**Cooled H_2O**	**Electrolysis H_2O**	**Cathode Products**	**Anode Products**	**O_2 exhaust**	**Cathode H_2O Recycle**	**H_2 Gas Mixture**
Stream	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
T [C]	25	55	60	55	55	55	55	60	60	60
P [Bar]	3	3	3	3	5	5	5	3	30	30
m_{total} [Kg/h]	785	785	185908	185908	185908	4796	181112	727	4702	94
n_{total} [kmole/h]	44	44	10328	10328	10328	305	10045	24	261	44
Liquid Phase [mole-fr	1	1	1	1	1	0.099	0.998	0	1	0
$X_{H2,L}$ [mole-frac]	0	0	0	0	0	4E-04	0	0	4E-04	0
$X_{O2,L}$ [mole-frac]	0	0	0	0	0	0	3E-05	0	0	0
$X_{H2O,L}$ [mole-frac]	1	1	1	1	1	1	1	0	1	0
Gas Phase [mole-frac]	0	0	0	0	0	0.901	0.002	1	0	1
$X_{H2,v}$ [mole-frac]	0	0	0	0	0	0.992	0.000	0.000	0	0.992
$X_{O2,v}$ [mole-frac]	0	0	0	0	0	0.001	0.921	0.921	0	0.001
$X_{H2O,v}$ [mole-frac]	0	0	0	0	0	0.007	0.079	0.079	0	0.007

5 MW Module @ BOL - Operation Mode: Full Load										
Name	**Pre-heated H_2 Gas Mixture**	**Heated H_2 Gas Mixture**	**O_2 Free- H_2 Wet Gas**	**Pre-Cooled H_2 Wet Gas**	**Cooled H_2 Wet Gas**	**Dried H_2**	**External HX Coolant In**	**External HX Coolant Out**	**Effluent Coolant In**	**Effluent Coolant Out**
Stream	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
T [C]	140	200	218	140	25	25	15	40	15	25
P [Bar]	30	30	30	30	30	30	1	1	1	1
m_{total} [Kg/h]	94	93	93	93	93	87	111545	111545	3860	3860
n_{total} [kmole/h]	44	44	44	44	44	43.3	6197	6197	207	207
Liquid Phase [mole-fr	0	0	0	0	0	0	1	1	1	1
$X_{H2,L}$ [mole-frac]	0	0	0	0	0	0	0	0	0	0
$X_{O2,L}$ [mole-frac]	0	0	0	0	0	0	0	0	0	0
$X_{H2O,L}$ [mole-frac]	0	0	0	0	0	0	1	1	1	1
Gas Phase [mole-frac]	1	1	1	1	1	1	0	0	0	0
$X_{H2,v}$ [mole-frac]	0.992	0.992	0.991	0.991	0.991	> 0.9995	0	0	0	0
$X_{O2,v}$ [mole-frac]	0.001	0.001	5.00E-06	5.00E-06	5.00E-06	5.0E-06	0	0	0	0
$X_{H2O,v}$ [mole-frac]	0.007	0.007	0.009	0.009	0.009	5.0E-06	0	0	0	0

Table 37 Electrolyzer 5 MW Module EOL Complete Mass Balances

5 MW Module @ EOL - Operation Mode: Full Load										
Stream Name	**D. H_2O Supply**	**Conditioned H_2O**	**H_2O Recycle**	**Cooled H_2O**	**Electrolysis H_2O**	**Cathode Products**	**Anode Products**	**O_2 exhaust**	**Cathode H_2O Recycle**	**H_2 Gas Mixture**
Stream	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
T [C]	25	55	60	55	55	55	55	60	60	60
P [Bar]	3	3	3	3	5	5	5	3	30	30
m_{total} [Kg/h]	739	739	238258	238258	238258	4517	233741	684	4429	88
n_{total} [kmole/h]	41	41	13237	13237	13237	287	12970	22	246	41
Liquid Phase [mole-fr	1	1	1	1	1	0.099	0.998	0	1	0
$X_{H2,L}$ [mole-frac]	0	0	0	0	0	4E-04	0	0	4E-04	0
$X_{O2,L}$ [mole-frac]	0	0	0	0	0	0	3E-05	0	0	0
$X_{H2O,L}$ [mole-frac]	1	1	1	1	1	1	1	0	1	0
Gas Phase [mole-frac]	0	0	0	0	0	0.901	0.002	1	0	1
$X_{H2,v}$ [mole-frac]	0	0	0	0	0	0.992	0.000	0.000	0	0.992
$X_{O2,v}$ [mole-frac]	0	0	0	0	0	0.001	0.921	0.921	0	0.001
$X_{H2O,v}$ [mole-frac]	0	0	0	0	0	0.007	0.079	0.079	0	0.007

5 MW Module @ EOL - Operation Mode: Full Load										
Name	**Pre-heated H_2 Gas Mixture**	**Heated H_2 Gas Mixture**	**O_2 Free- H_2 Wet Gas**	**Pre-Cooled H_2 Wet Gas**	**Cooled H_2 Wet Gas**	**Dried H_2**	**External HX Coolant In**	**External HX Coolant Out**	**Efffluent Coolant In**	**Efffluent Coolant Out**
Stream	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
T [C]	140	200	218	140	25	25	15	40	15	25
P [Bar]	30	30	30	30	30	30	1	1	1	1
m_{total} [Kg/h]	88	88	88	88	88	82	142955	142955	3862	0.3862
n_{total} [kmole/h]	41	41	41	41	41	40.8	7942	7942	208	208
Liquid Phase [mole-fr	0	0	0	0	0	0	1	1	1	1
$X_{H2,L}$ [mole-frac]	0	0	0	0	0	0	0	0	0	0
$X_{O2,L}$ [mole-frac]	0	0	0	0	0	0	0	0	0	0
$X_{H2O,L}$ [mole-frac]	0	0	0	0	0	0	1	1	1	1
Gas Phase [mole-frac]	1	1	1	1	1	1	0	0	0	0
$X_{H2,v}$ [mole-frac]	0.992	0.992	0.991	0.991	0.991	> 0.9995	0	0	0	0
$X_{O2,v}$ [mole-frac]	0.001	0.001	5.00E-06	5.00E-06	5.00E-06	5.0E-06	0	0	0	0
$X_{H2O,v}$ [mole-frac]	0.007	0.007	0.009	0.009	0.009	5.0E-06	0	0	0	0

Appendix C.6 Footprint Sizes & Estimations

Table 38, Table 38, Table 39,Table 40, Table 41 and Table 42 show a summary of the design considerations used during the sizing procedures.

Electrolyzer Stack

Table 38 Electrolyzer Stack Sizing Summary

Parameter	Definition	Value
A_{active}[cm^2]	Cell Active Area	1500
A_{active}/A_{total}[-]	Ratio active area/total area	1/3*
A_{total} [cm^2]	Total Cell Area	4400
L_{total}[cm]	Total Length	80
W_{total}[cm]	Total Width	55
P_{stack}[MW]	Stack Power	2.5
I_{max} [A/cm^2]	Current Density	2.3
V_{max} [V]	Cell Voltage	1.95
N_{cells}[-]	Number of cells per stack	372
$B.P._{Material}$[-]	Material Bipolar Plate	Graphite
$B.P_{thickness}$ [mm]	Bipolar Plate Thickness	2
V_{cell}[cm^3]	Cell Volume	1760
H_{total}[cm]	Total Cell Height	~1.65**
W_{Stack} [Kg]	Stack Weight	5167
*Reference Cummins 1500E cell stack (small) **assuming height is mainly function of bipolar plate thickness, two bipolar plates per cell and 10% extra height for the base support and electrical connections		

Oxygen Separator

Table 39 5 MW Oxygen Separator Sizing Summary

Parameter	Definition	Value
Type	Separator Type	Horizontal
m_{vapor}[kg/s]	Vapour Flow Rate	0.2
m_{Liquid}[kg/s]	Liquid Flow Rate	50
U_t [m/s]	Settling Velocity	1.33
D_{min}[m]	Minimum Diameter of the Vessel	0.2
$t_{vapor,settling}$[s]	Minimum Vapor time to settle**	10
$f_{v,min}$ [m]	Liquid Height in the vessel (Assumed)	0.5
$t_{Liquid,Holdup}$[s]	Minimum Liquid Hold Up**	30
D_{Vessel}[m]	Vessel Diameter for Hold up	1
Length [m]	Vessel Length for Hold up	3.9
V_{Vessel} [m^3]	Vessel Volume for Hold up	1.54
** From Product Vendors		

Hydrogen Separator

Table 40 5 MW Hydrogen Separator Sizing Summary

Parameter	Definition	Value
Type	Separator Type	Vertical
m_{vapor}[kg/s]	Vapour Flow Rate	0.03
m_{Liquid}[kg/s]	Liquid Flow Rate	1.31
U_t [m/s]	Settling Velocity	0.37
D_{min}[m]	Minimum Diameter of the Vessel	0.1
$t_{vapor,settling}$[s]	Minimum Vapor time to settle**	10
$f_{v,min}$ [m]	Liquid Height in the vessel (Assumed)	0.5
$t_{Liquid,Holdup}$[s]	Minimum Liquid Hold Up**	30
D_{Vessel}[m]	Vessel Diameter for Hold up	0.35
Length [m]	Vessel Length for Hold up	0.8
V_{Vessel} [m^3]	Vessel Volume for Hold up	0.08
** From Product Vendors		

Internal Heat Exchanger

Table 41 Internal Heat Exchanger Sizing Summary

	Parameter	Definition	Value
General	Q[kW]	Duty	1390
	A [m^2]	Area Transfer	39
	$U_{assumed}$ [W/m^{2}K]	Heat Transfer Coefficient (assumed)	3000
	U_{cal}[W/m^{2}K]	Heat Transfer Coefficient (calculated)	3050
	$Plate\ Tickness$ [mm]	Plate Thickness	0.75
	W_{eff} [m]	Effective Plate Width	0.5
	H_{eff}[m]	Effective Plate Height	1
	$A_{plate,eff}$[m^2]	Effective Plate Transfer Area	0.5
	N_{plates}[-]	Number of Plates	79
	# Channels per pass	Number Channels per pass	40
	Plate Spacing [mm]	Plate spacing	3
	$A_{channel,cross}$ [m]	Channel Cross Sec. Area	0.0015
	$D_{hydraulic}$[m]	Hydraulic Diameter	6.00E-03
	L_{eff}[m]	Exchanger Length (plates +spacing)	0.3
	Material [-]	Plate Material	SS 316
Hot Side (Recycling Water)	$T_{hot,in}$ [C]	Temperature Hot In	60
	$T_{hot,out}$[C]	Temperature Hot Out	55
	$m_{hot,in}$ [kg/s]	Flow Mass Hot	33
	ΔP_{Hot} [Bar]	Pressure Drop Hot side	0.34
	ΔP_{port} [Bar]	Pressure Drop Port Hot Side	0.2
	$V_{channel,hol}$ [m/s]	Velocity Channel Hot Side	1.1
Cold Side (Cooling Process Water)	$T_{cold,in}$ [C]	Temperature Cold In	40
	$T_{cold,out}$[C]	Temperature Cold Out	50
	$m_{cold,in}$ [kg/s]	Flow Mass Cold	66
	ΔP_{Hot} [Bar]	Pressure Drop Hot side	0.1
	ΔP_{port} [Bar]	Pressure Drop Port Hot Side	0.1
	$V_{channel,hol}$ [m/s]	Velocity Channel Hot Side	0.6

External Heat Exchanger

Table 42 External Heat Exchanger Sizing Summary

	Parameter	Definition	Value
General	Q[kW]	Duty	4170
	A [m^2]	Area Transfer	120
	$U_{assumed}$ [W/m^{2}K]	Heat Transfer Coefficient (assumed)	2105
	U_{cal}[W/m^{2}K]	Heat Transfer Coefficient (calculated)	2107
	$Plate\ Tickness$ [mm]	Plate Thickness	0.75
	W_{eff} [m]	Effective Plate Width	0.5
	L_{eff}[m]	Effective Length	1.5
	$A_{plate,eff}$[m^2]	Effective Plate Transfer Area	0.75
	N_{plates}[-]	Number of Plates	161
	# Channels per pass	Number Channels per pass	80
	Plate Spacing [mm]	Plate spacing	3
	$A_{channel,cross}$ [m]	Channel Cross Sec. Area	0.0015
	$D_{hydraulic}$[m]	Hydraulic Diameter	6.00E-03
	$L_{eff}[m]$	Exchanger Length (plates +spacing)	0.6
	Material	Plate Material	Titanium
Hot Side (Cooling Process Water)	$T_{Hot,in}$ [C]	Temperature Hot In	50
	$T_{Hot,out}$[C]	Temperature Hot Out	40
	$m_{hot,in}$ [kg/s]	Flow Mass Hot	99
	ΔP_{Hot} [Bar]	Pressure Drop Hot side	0,3
	ΔP_{port} [Bar]	Pressure Drop Port Hot Side	0,2
	$V_{channel,hol}$ [m/s]	Velocity Channel Hot Side	0,8
Cold Side (Sea Water)	$T_{cold,in}$ [C]	Temperature Cold In	20
	$T_{cold,out}$[C]	Temperature Cold Out	35
	$m_{cold,in}$ [kg/s]	Flow Mass Cold	66
	ΔP_{Hot} [Bar]	Pressure Drop Hot side	0,3
	ΔP_{port} [Bar]	Pressure Drop Port Hot Side	0,2
	$V_{channel,hol}$ [m/s]	Velocity Channel Hot Side	0,8

Water Desalinator

Table 43 shows, reference reverse osmosis characteristics from quotings

Table 43 Reverse Osmosis Reference Size & Cost from quoting

Parameter	RO Desalination (Single & Second Step)$^{+}$		Single Step RO Desalination
	Large Scale	Small Scale	Small Scale
Distillate Capacity [m^3/d]	3800	100 m^3/d	100 m^3/d
Dimensions (LXW) [m]	15 x 10	7 x 4	2.8x1.7
Free available height [m]	4 m	3 m	2
Power installed [KW]	~700 kW	~ 40 kW	18.5
Investment (M€)	3	0.3	--
Weight(Tonnes)	--	--	2.5

$^{+}$ This system includes second pass reverse osmosis, cleaning unit, Electro-deionization unit, and control panel and is sized to provide water at the required quality to be injected directly into the electrolyzer system

$^{++}$ This system includes only single step reverse osmosis and is sized to provide drinking water quality. Further treatment is required to reach the electrolyzer water quality.

Table 44 shows reference thermal desalination characteristics from quotings

Table 44 Thermal Desalination Reference Size & Cost from quoting

Parameter	Multi Effect Distillation (MED)	Multi Stage Flash (MSF)
Distillate Capacity [m^3/d]	117	1500
Dimensions (LXW) [m]	2.8x1.93	12x3.9
Free available height [m]	2.6	4
Heat Consumption [KW]	1215	-
Weight [Tonnes]	6.3	-
Investment (M€)	0.33	2.25

Power Converters & Transformer

Table 45 shows reference dimensions and weights for different converter technologies used in offshore wind turbine applications.

Table 45 Reference Footprint Current Rectifiers on Offshore Wind Turbines

Component	Voltage (V)	Power (MW)	Dimensions WxDxH* [m]	Weight [Tonnes]	Source
IGBT Rectifier Face to face	690	4.6	2.9x0.6x2	2.6	[127]
	690	3	2.3x0.6x2	2	
	690	1.6	1.4x0.6x2	1.2	
IGBT Rectifier Arrangement	690	4.6	1.45x1.2x2	2.3	
IGCT Rectifier	0-3400	7	3.5x2.28x2.45	5.3	[128]
Inverter In-line	0-3400	12	5.96x1.28x2.46	7.3	[128]
Turbine Transformer (50 Hz)	66KV	5	1.17x2.66x2.65	-	[129]
Turbine transformer (50 Hz)	20KV	2.3	0.76x2.16x2.13	5	[130, 131]

* Width x Depth x Height

** As a reference, these dimensions meet the specifications of a 5 MW Wind Turbine entrance door

Appendix D Complement Economic Modelling

Wind Resources at Ijmuiden Ver.

Table 46 show the wind resources characteristics used for the economic assesment.

Table 46 Reference Wind Resources at IJmuiden Ver. at 120 m above MSL

Alfa [º]	**Freq [%]**	**Weibull A [m/s]**	**Weibull K [-]**
0	6.194	9.715	2.171
30	5.702	9.166	2.354
60	6.34	9.308	2.471
90	6.387	9.709	2.419
120	5.55	9.279	2.338
150	4.804	9.330	2.092
180	7.301	11.284	2.179
210	13.45	13.134	2.394
240	14.8	12.928	2.437
270	11.36	11.957	2.202
300	9.751	11.200	2.191
330	8.36	11.127	2.173
All	100	11.189	2.177
Wind Shear exponent α = 0.09			

Sea Characteristics

Table 47 show the site sea characterists used for the economic assesment.

Table 47 IJmuiden Site Sea Characteristics [132, 133]

Wave Height [m]	**Value**
High Astronomical Tide [m_{MSL}]	0.8
Low Astronomical Tide [m_{MSL}]	-1
Storm Surge [m]	+5.35
Water Depth [m]	28 , 30, 40
50 Yrs. Significant Wave Height [m]	7.7
MSL: Mean Sea Level	

Applied Models Cost Estimation

Table 48 shows which costs models from the TNO calculator tool were used in each study case.

Table 48 Cost Models Used for the Studied Cases

Module	Included		Module	Included	
	Case 1	Case 2		Case1	Case2
Wind Turbine	yes	yes	**Transfer Pipeline Manifold**	No	Yes
Support Structure	Yes	Yes	**Offshore Compression Substation**	No	Yes
Wind Farm Electrical System	Yes	No	**H_2 Export Pipeline**	No	Yes
Electrical Export System	Yes	No	**Onshore Compression**	Yes	No
O&M Turbine	yes	yes	**Electrolyzers**	Yes	Yes
RO Desalination	yes	yes	**O&M Added Systems**	Yes	Yes

BOP Reference Efficiency

Figure 50 depicts an example of the power losses of different components in the electrolyser system as a function of the input load.

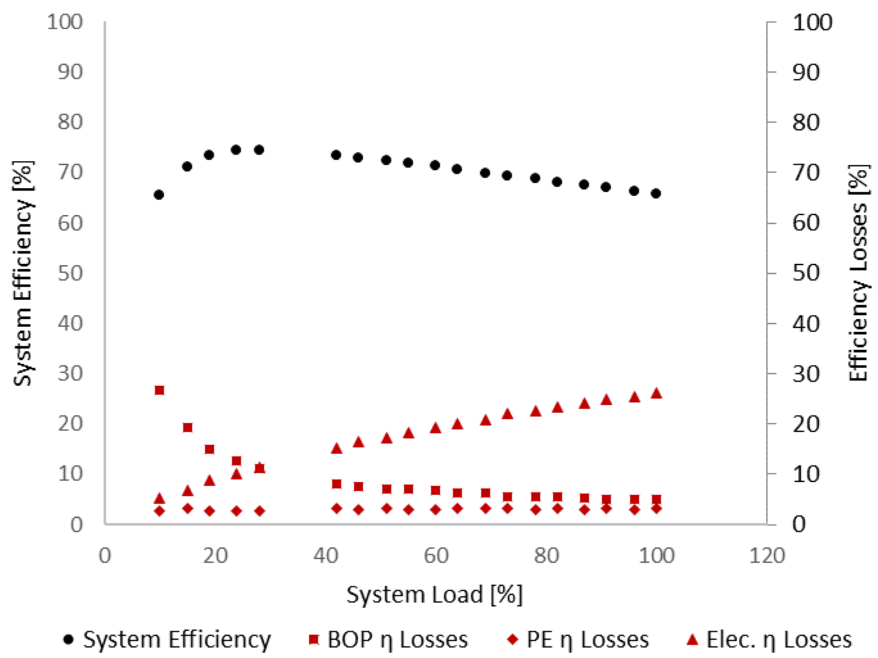

Figure 50 'typical' PEM Electrolysis System Efficiency and Balance of Plant (BOP), Power Electronics (PE) and Electrolyzer (Elec.) Efficiencies losses. Adapated from ITM [35]

Fitted Polynomial Power vs H2 production

Figure 51 shows an example of fitted curves to determine the hydrogen power production as a function of the power input.

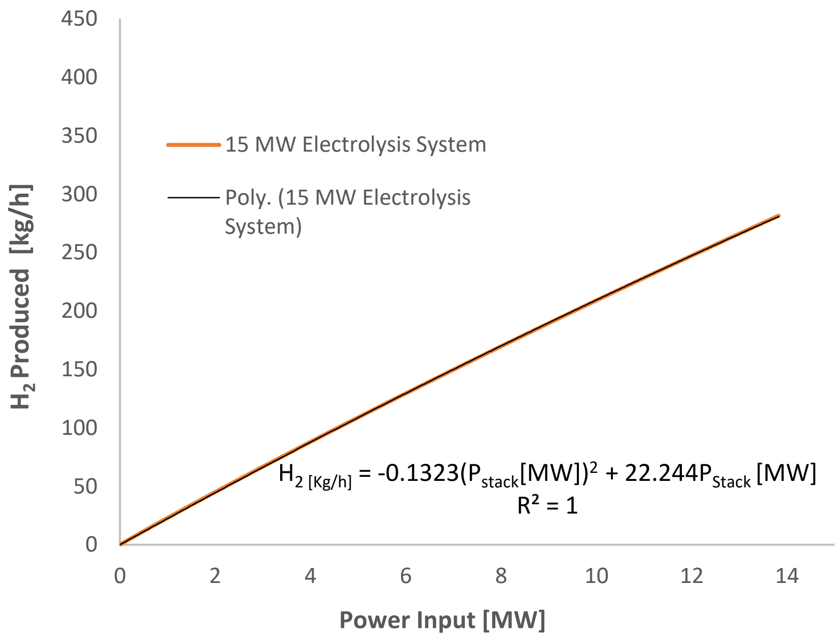

Figure 51 Fitted Curve Hydrogen Production at Different Power Inputs

Electrolyzer Cost

Table 49 shows the reference cost used for the economic analysis provided by in-house analysis at TNO

Table 49 Reference Cost 1 MW PEM at 2020 and future electrolysis System

Component	Cost Contributors	1 MW (2020)	1 MW (Future)*	
		Cost [€/KW]	Learning Factor [%]	Cost [€/KW]
Electrolyzer Stack	Materials	200	0	200**
	Manufacturing	200	30	140
	Total	400	30	340
BOP	Equipment & Manufacturing	220	20	160
	Overhead	235	70	76.5
	Total	455	52	236.5
Power Electronics	**Total**	105	5	99.75
Total Uninstalled Capital Cost [€/KW]**		960	676	
Installation Cost [% of Uninstalled Capital cost]		50%	50%	

*Estimated when manufacturing standardization and market volume is reached, applying learning factors provided by TNO
** Assuming material costs remain unchanged in the near future

Table 50 shows the reference scale & installation cost factors used during the economic analysis.

Table 50 In house TNO Scale and Installation Factors for the Electrolyzer System

Parameter	Scale Factor [-]	Installation Factor [% CAPEX]
PEM Stack	0.95*	20
Balance of Plant	0.85**	100
Power Electronics	0.90***	100

Reasoning
* Almost modular small benefit for scaling up mostly up numbering
** BOP benefits the most from scaling up the total capacity
*** Largely modular, some economy of scale in installation

Table 51 shows the reference OPEX cost as a function of system size reported in the literature.

Table 51 Electrolyzer System Annual OPEX Cost as a function of System Size. Reproduced from [116]

System Size [MW]	OPEX* [% initial CAPEX/year]
1	5
5	2.2
10	2.2
20	1.85
50	1.64
100	1.61
250	1.54
1000	1.52

* Excluding electricity and stack replacement cost; This cost is composed of consumables (~1.5 [% initial CAPEX/year]) and labour (dependant of system size) cost.

An example of the “hydrogen curve” (hydrogen production as a function of wind speed) determined for the economic analysis is shown in Figure 52 below

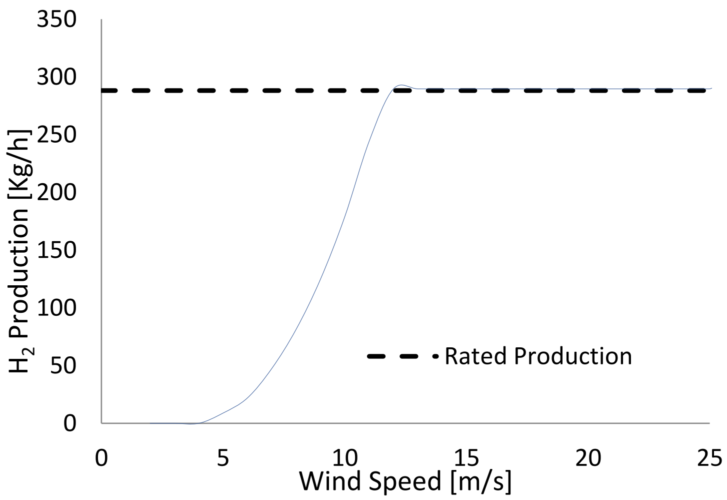

Figure 52 Generic Hydrogen Turbine Production Curve. For a 15 MW rated Turbine, 240 rotor diameter. Assuming a modular 15 MW electrolysis system

Compressor Cost

Table 52 shows the gathered information regarding current compressor cost and dimensions.

Table 52 Reference Hydrogen Compressor System Cost

Power [MW]	Rate [Nm^3/h]	Pin-Pout	Cost* [M€]	Weight [Ton]	Dimensions [m]	Reference
15	167000	40-270	6	-	-	Internal Quoting TNO
15	167000	40-270	5.7	180	35x30x8	Internal Quoting TNO
0.9	20249	30-80	3	-	-	[134] North Sea
0.1	2025		0.6	-	-	
0.012	203		0.2	-	-	
6.9	190004	30-70	5	Compressor:200 Motor:70	25x16	Internal TNO Project
3.4	75000	32-93	2-3	-	15x12x8	NEA Presentation & webinars
10-20	-	-	5-10	-	25x30x8	
0.235	4400	25-85	1-2	-	10x4x5 (excl. Cooling)	

*In general, refer to compressor system cost: including motor drive, compressor, cooling, dampeners, etc.

Figure 53 show the fitted compression cost curve as a function of compression curve using the information reported in Table 52.

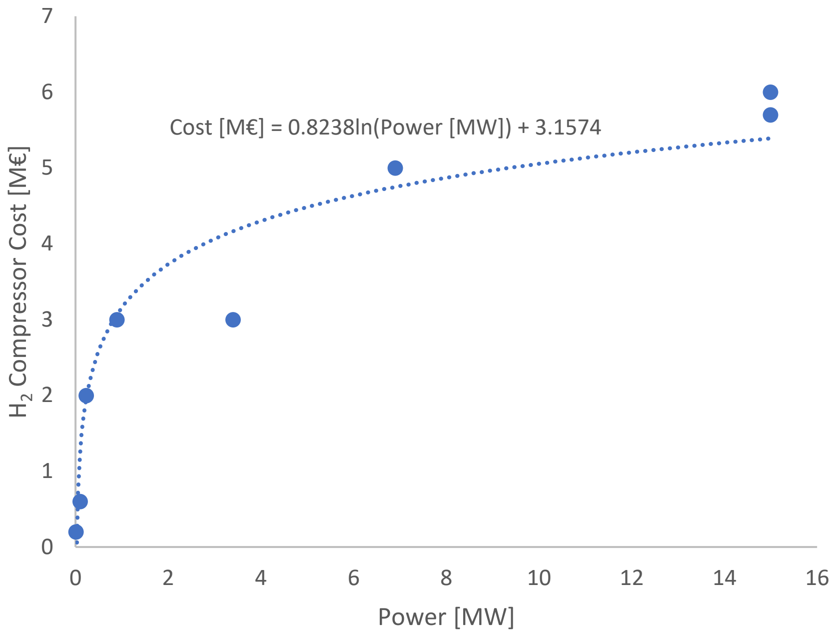

Figure 53 Hydrogen Compression Cost as a Function of Compression Power. From Internal TNO quoting and provided/reported industry data

Pipeline Pressure Losses

The pressure losses in the pipeline are calculated as per equation (13):

$$\Delta P\ [bar] = f\,\frac{\mu\, L\, v^2 \rho}{2\o_{pipeline}} \tag{13}$$

Where $f[-]$ is the friction factor, $\mu\ \left[\frac{kg}{m\ s}\right]$ is the gas viscosity, $v\ \left[\frac{m}{s}\right]$ is the velocity of the gas in the pipeline, $\rho\ \left[\frac{kg}{m^3}\right]$ is the density of the gas and $\o_{pipeline}[m]$ is the pipeline diameter.

The friction factor is calculated from the Swamee Jain (1976) equation:

$$f\ [-] = \frac{1.325}{\left(\ln\left(\frac{\varepsilon}{3.7 * \o_{pipeline}} + \frac{5.75}{Re^{0.9}}\right)\right)^2} \tag{14}$$

Where ε is the roughness of the pipeline, Re is the Reynolds number, and $\o_{pipeline}$is the pipeline diameter

Pipeline costs

Figure 54 gas pipeline cost per kilometer as a function of diameter from three sources available in literature. The data points reported for EBN-Gasunie & BBL and DNV GL sources are ploted directly in the figure. The Parker points are obtained from the fitted equation reported by Parker from historical data of several natural gas pipeline installation projects.

$$CAPEX_{Pipeline}[M€] = \left(EU\left(A\, D_{Pipe}^{2} + BD_{pipe} + C\right) * L + C_{install}\right) \qquad (15)$$

Where D_{pipe}[in] is the pipeline diameter; L [miles] is the pipeline length, A [-] = 924.5, B [-] = 12.040 and C [-]=260.280 and $C_{install}$=378750 are fitting factors

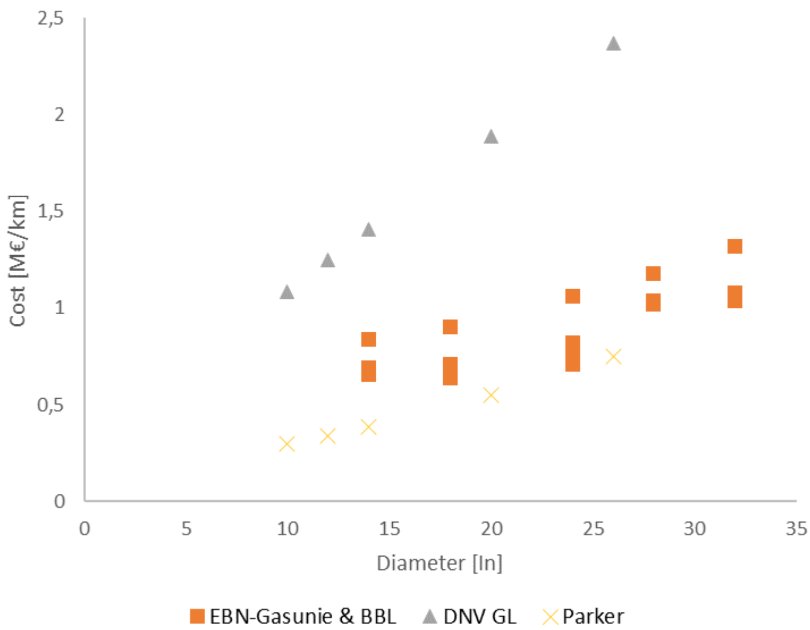

Figure 54 Pipeline Cost per km as a function of Diameter [121, 119, 135]

Detailed Cost Contributors 2020 Scenario

Table 53 reports the estimated cost in €/kg of hydrogen produced for the different components in the hydrogen wind farms.

Table 53 2020 Cost Contributors Hydrogen Wind Farm

Cost Component	Offshore Electrolysis [€/kg]	Onshore Electrolysis [€/kg]
Turbine	0.86	0.88
Foundation	0.45	0.41
Hydrogen Transfer	0.18	0.01
Electricity Transfer	0.00	0.45
Electrolyzer	1.03	0.97
PEM Stack Replacement	0.19	0.16
RO Desalinator	0.01	0.01
Wind Farm Installation	0.11	0.14
O&M Turbine	0.87	0.90
O&M H_2 Production & Compression	0.29	0.24
TOTAL LCOH	4.0	4.2
Annual H_2 Production [Tonnes/year]	68939	66864

Sensitivity 2020 Scenario

Figure 55 depicts the sensitivity analysis for the cost penalty factors applied in the economic model using 2020 cost values.

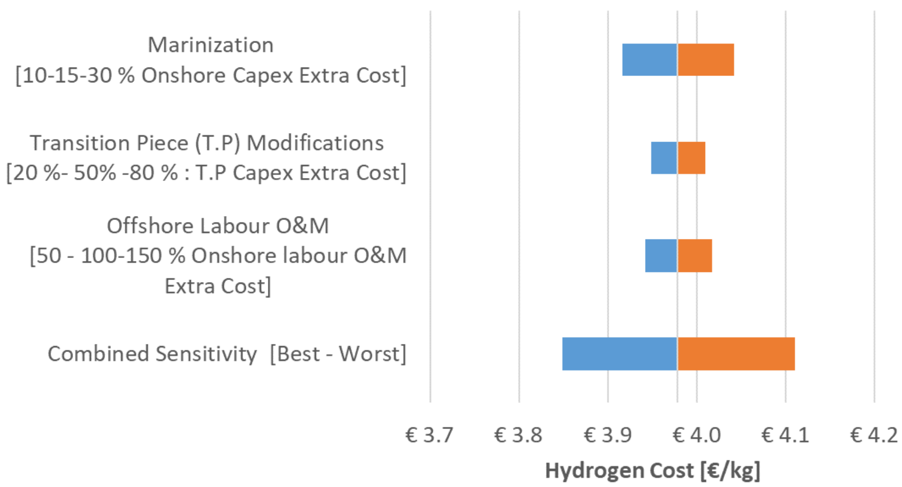

Figure 55 Sensitivity of Cost Penalty Factors Applied in the Economic Model 2020

Cost Distribution 2020 & Future Scenarios

Figure 56 depicts the cost distribution of the different elements in an Hydrogen-Wind Farm with current (2020) technology and costs.

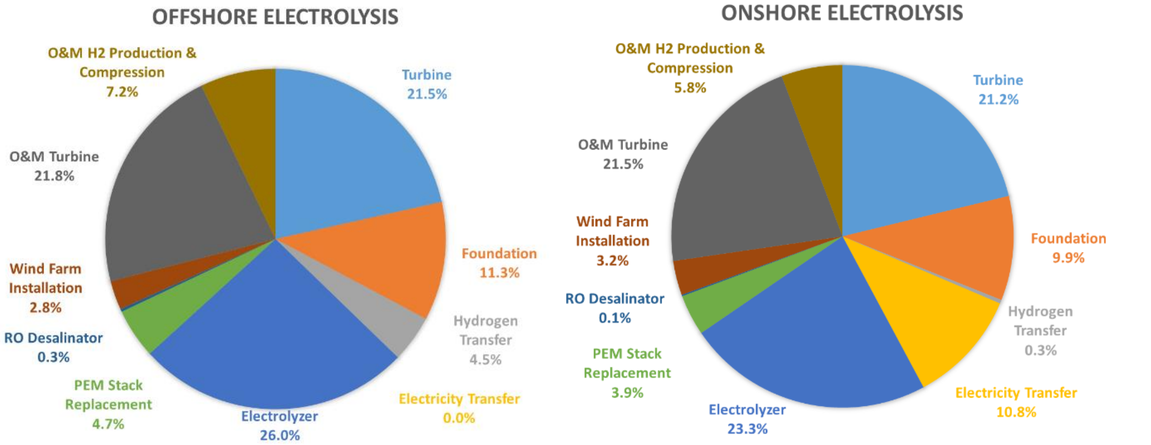

Figure 56 Hydrogen-Wind Farm Cost Distribution for Offshore (left) and Onshore (right) Electrolysis. PEM Electrolysis with 2020 Technology and Cost

Figure 57 depicts the cost distribution of the different elements in an Hydrogen-Wind Farm with future (2025) assumed innovations and expected cost reduction in the Capex of the electrolyzer.

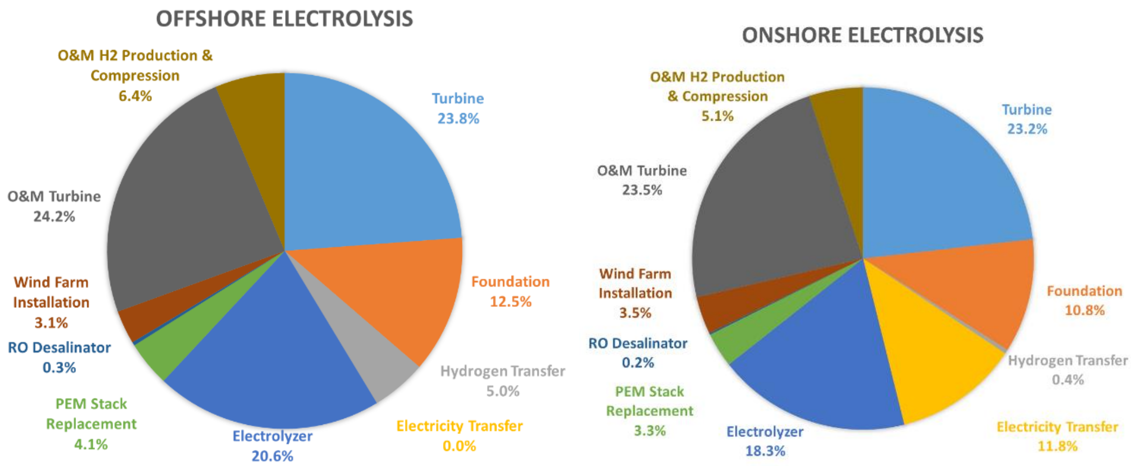

Figure 57 Hydrogen-Wind Farm Cost Distribution for Offshore (left) and Onshore (right) Electrolysis. PEM Electrolysis in which cost reductions due to Standardization and Efficiency improvements (at 2025) have been reached.

O&M Considerations

Table 54 shows some reference failure rates for different equipment involved in the offshore wind turbine electrolyser system. As shown in the table, the components that most influence this failure rate those in direct contact with seawater, such as seawater lifting pumps (for the water desalination and cooling systems) and the seawater heat exchanger.

Table 54 Estimated Yearly Failure Rates for some Components in the Integrated System

Component	[Failures/ Year]	Notes	Source
Electrolyzer Stack	0.1	The main failure expected is degradation which can be easily identified. The maintenance strategy can me adapted to minimize offshore logistics impact. For example, stack replacement activies can be merge with turbine maintenance activites.	Product Vendors
Seawater Heat Exchanger	0.45	Accelerated stack degradation due to high temperatures. After some time hydrogen production is expected to stop to protect the electrolyzer.	[136]
Pump Sea Water Lift	1.45	Production of Hydrogen when water is unavailable. This component has a high failure rate. A spare unit could be used to increase availability.	
Circulation Pumps	0.26	Potential built up of hydrogen within the oxygen side of the stack. However, the safety system is expected to trigger when this situation is reached	
Gas Liquid Separator	0.07	No major failures expected. In case of vessel fracture, the safety system is expected to trigger as leaked hydrogen will start to built up within the PEM module.	
RO Filters	3	Filters in RO need to be exchanged relatively soon, which conflict with offshore wind turbine schedules. Spare filters with automatic switching can be used to mitigate this issues	Product Vendor
RO Membranes	0.25	RO membranes need to be exchanged every 4 years in average as they degrade. The degradation can be identified and thus similar to the electrolyzer stack merging maintenance strategies to mitigate the impact of this replacements can be used.	
Onshore H_2 Pipeline	0.0126**	Only applies for onshore cases. However it serves as a reference for the scale of failures	[137, 138]
Offshore Pipeline (steel)	0.00879***	Relatively low failure rate. Failures are normally detected when pressure start decreasing in the pipeline. Failure rates of natural gas pipelines at the North Sea.	[139]
Offshore Pipeline (flexible)	0.101^{+}	Failure rates of flexible natural gas pipelines at the North Sea	

*Assuming MTTR ; **Assuming 100 km pipeline, the reported figure is 0.126 Failures/year/1000 km (onshore)

*** Assuming 100 km pipeline, the reported figure is $8.79*10^{-5}$ Failures/year/km

+ Assuming 100 km pipeline, the reported figure is $1.01*10^{-3}$ Failures/year/km