Indo-German
Energy Forum

Green Hydrogen Production from Offshore Wind in Tamil Nadu and Gujarat

Report by:

DNV

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Innovation Norway

WFO

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GOVERNMENT OF INDIA
MINISTRY OF NEW
AND RENEWABLE ENERGY

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LIST OF ABBREVIATIONS

The following table lists some of the abbreviations used in this Report.

Abbreviation	Meaning
@	at the rate of
AEP	Annual Energy Production
CTV	Crew Transfer vessel
EIA	Environment Impact Assessment
ERA-5	European Centre for Medium-Range Weather Forecasts (ECMWF) Re-Analysis - 5
FOWIND	Facilitating offshore wind in India
FOWPI	First offshore wind farm in India
GEOS-5	Goddard Earth Observing System Data Assimilation System Version 5
GIS	Gas Insulated Switchgear
GJ	Gujarat
HAT	Highest astronomical tide
HVDC	High Voltage Direct Current
LAT	Lowest Astronomical Tide
LCOE	Levelized Cost of Energy
LiDAR GUJ	LiDAR in Gujarat
MERRA-2	Modern-Era Retrospective Analysis for Research and Applications (version 2)
MNRE	Ministry of New and Renewable Energy
MSL	Mean Sea Level
NASA	National Aeronautics and Space Administration
NIWE	National Institute of Wind Energy
NIWE	National Institute of Wind Energy
OSS	Offshore substation
OWF	Offshore Wind Farm
LCoH	Levelized Cost of hydrogen
LCoE	Levelized Cost of Energy
PLF	Plant Load Factor (equivalent to Capacity Factor)
RTM	Regulated Tariff Mechanism
SOV	Service Operation Vessel
SPMT	Self-Propelled Modular Transporters
SRTM	Shuttle Radar Topography Mission
STATCOM	static synchronous compensator
TN	Tamil Nadu
TBCB	Tariff Based Competitive Bidding
VMD	Virtual Met Data
VMD_DHA	Virtual Met Data at Dhanushkodi Mast
VMD_Lid	Virtual Met Data at the Lidar location
WAsP	Wind Atlas Analysis and Application Program
WACC	Weighted average cost of capital
WRF	Weather Research and Forecasting
WTG	Wind Turbine Generator
XLPE	Cross-linked polyethylene

EXECUTIVE SUMMARY

Objective

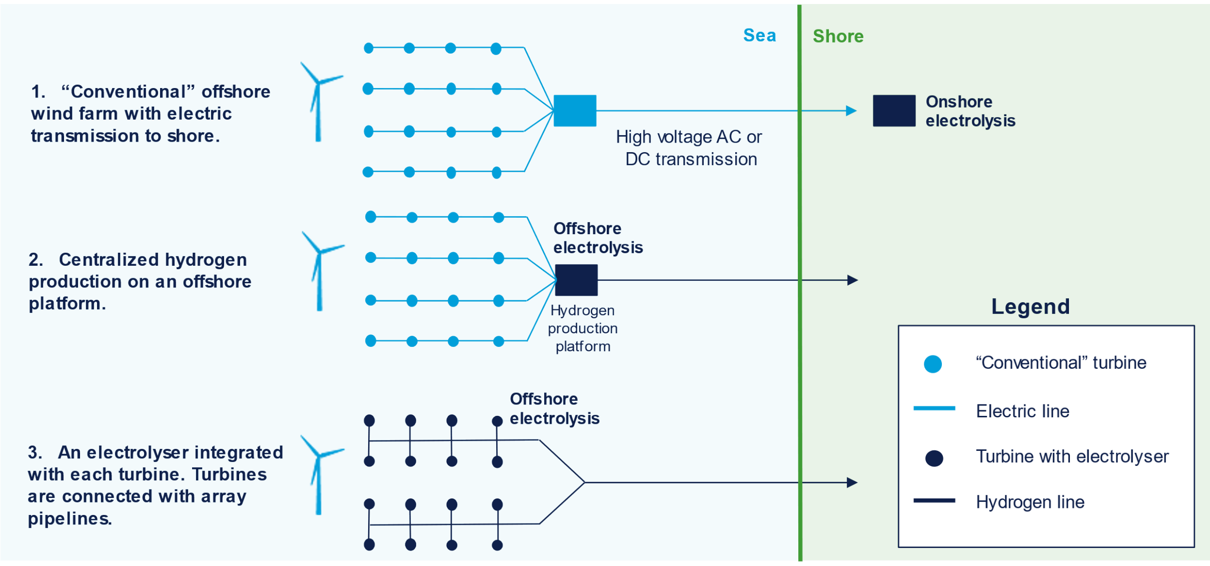
India's goal of achieving Net Zero emissions by 2070 necessitates the exploration of viable solutions to address the challenge of hard-to-abate sectors, which are difficult to electrify. While electrification and renewable energy sources can effectively curb emissions from fossil fuels by replacing them, the role of green hydrogen becomes crucial in attaining the Net Zero objective. Recognizing its critical importance, the Indian Government has introduced the National Green Hydrogen Mission, aimed at establishing a comprehensive action plan and facilitating the development of a suitable ecosystem.

Under this mission, the objective is to build the necessary capabilities to produce a minimum of 5 million Metric Tonnes (MMT) of green hydrogen per annum by 2030, with the potential to increase production to 10 MMT per annum to meet growing export market demands. Achieving this 10 MMT per annum target would require an additional 250GW of renewable energy capacity. Furthermore, as the government has already set a target of installing 500GW of non-fossil fuel-based electricity capacity by 2030, the requirement for renewable energy sources becomes substantial due to the need for electrification, electric mobility, green hydrogen production, and the year-on-year increase in demand resulting from population and economic growth.

In this context, offshore wind energy emerges as a significant proposition for renewable energy sources due to the absence of challenges related to land availability and acquisition. However, uncertainties remain regarding the overall potential for green hydrogen production from offshore wind in India and the optimal design of offshore wind farms in conjunction with green hydrogen production. This study aims to address these questions and explore potential solutions.

Optimized Configuration

The figure below provides three possible configurations for connecting an electrolyser plant to an offshore wind farm.



1. **The first configuration** features a conventional wind farm, but instead of connecting to a grid, it is directly connected to an electrolyser plant which is located onshore.
2. **The second configuration** still resembles a conventional offshore wind farm but will not be connected to the grid. Instead, the electrolyser plant is part of the infrastructure to transport energy to shore. The electrolyser plant is located on a centralized platform (comparable to a substation) and is receiving electricity from the array cables, which are used to produce hydrogen from seawater. Hydrogen is transported to the shore using a hydrogen export pipeline.

3. **The third configuration** integrates the hydrogen production at the turbine. A smaller electrolyser unit is directly connected to the turbine to generate hydrogen and will omit the requirement for array cables. Instead, array pipelines are used, which transport the hydrogen to a central point, where it will be fed into the hydrogen export pipeline and transported to shore.

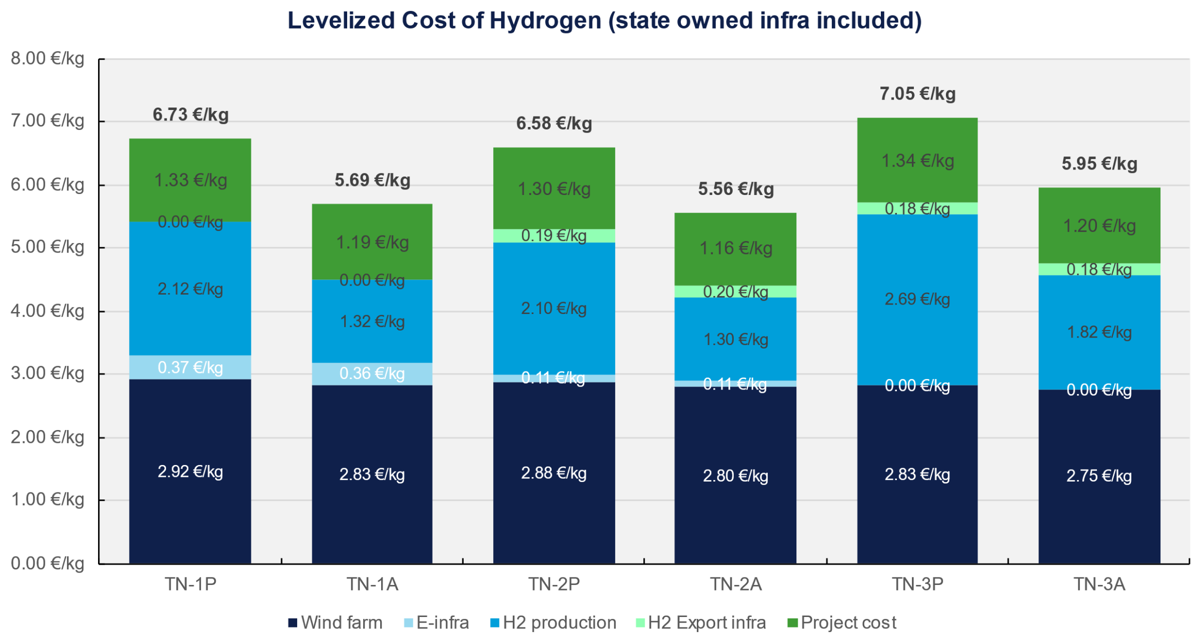
For a comparative study through LCOE for each configuration, a techno-commercially viable conceptual design for a 1 GW offshore wind farm in each of Gujarat and Tamil Nadu has been considered. 20 MW turbine model, jacket foundation type, 66 kV internal array cabling and 220kV export cable have been considered for the 1GW wind farm. Besides, 2 scenarios have been considered for the modelling purpose. In Scenario 1, Developer's responsibility is to offshore substation whereas in Scenario 2 developer's responsibility is till onshore grid integration.

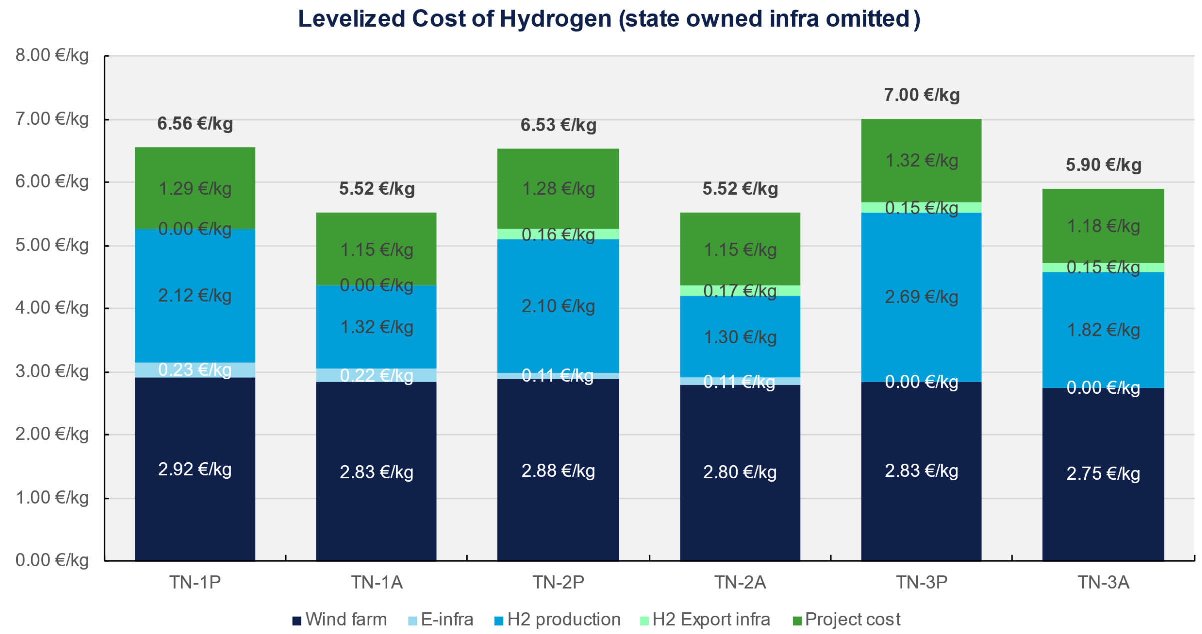
LCOE for the three offshore hydrogen production topologies (denoted by numbers 1 – 3) for the Tamil Nadu and Gujarat 1 GW wind farms has been calculated based on the abovementioned parameters. Furthermore, both PEM and Pressurized Alkaline technologies are analysed (denoted by the letter P/A). The tables below show some key characteristics of the analysed value chains.

Case ID	Topology	Export infrastructure	Turbine rating	ELX rating	ELX type
TN-1P	Onshore Centralized	HVAC (1x2 substations, 3 cables)	50 x 20 MW	20 x 50 MW (1 plant)	PEM
TN-1A	Onshore Centralized	HVAC (1x2 substations, 3 cables)	50 x 20 MW	20 x 50 MW (1 plant)	ALK
TN-2P	Offshore Centralized	H2 pipeline (10.8")	50 x 20 MW	20 x 50 MW (2 plants)	PEM
TN-2A	Offshore Centralized	H2 pipeline (10.8")	50 x 20 MW	20 x 50 MW (2 plants)	ALK
TN-3P	Offshore Decentralized	H2 pipeline (10.8")	50 x 20 MW	50 x 20 MW (50 plants)	PEM
TN-3A	Offshore Decentralized	H2 pipeline (10.8")	50 x 20 MW	50 x 20 MW (50 plants)	ALK

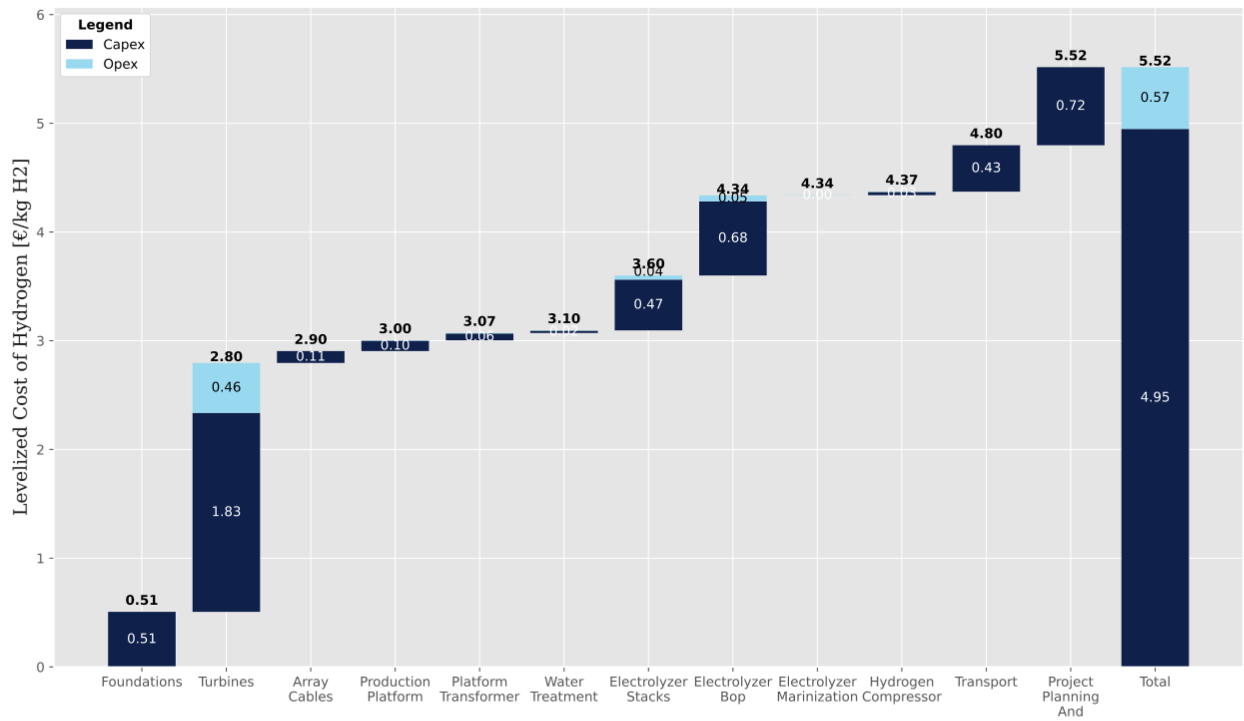
The onshore centralized scenarios are assumed to exist in isolation from the mainland electrical grid. The comparative analysis and result patterns are same for the Tamil Nadu and Gujarat and hence, here only Tamil Nadu results are presented.

As can be seen in the figures below, the centralized production topologies (1 & 2) feature a more attractive LCOH compared to the decentralized production topology (3). Furthermore, it can be observed that Pressurized Alkaline (A) features a more cost-effective profile than PEM (P) for 2030. It should be noted that the offshore production topologies come with relatively large uncertainties with regard to the cost of offshore installation and maintenance, as well as the "marine readiness" of electrolysis equipment in general for 2030.





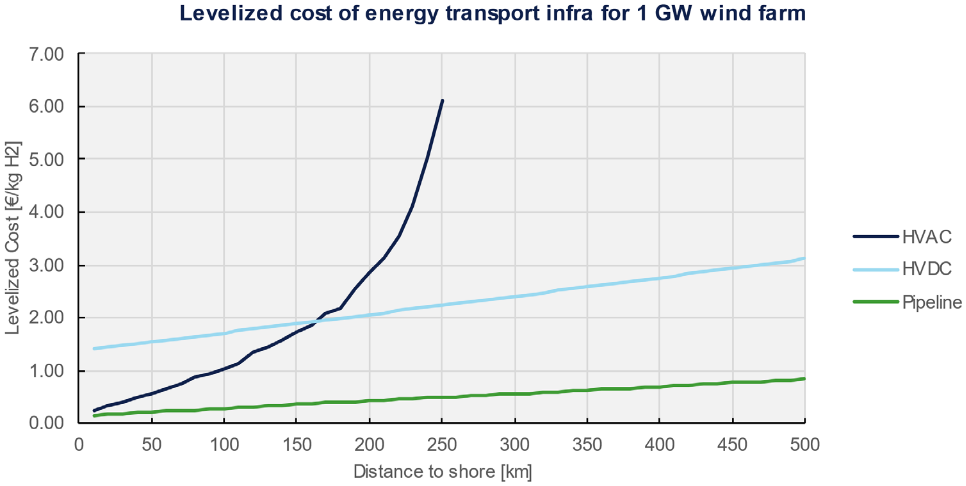
To take a closer look at the most cost-effective option: TN-2A – offshore centralized hydrogen production, using pressurized alkaline electrolysers. The following figure features a cost split per category and highlights the CAPEX and OPEX share of each category.



Energy Transmission Vector: Electricity vs. Pipeline

In order to compare the cost-effectiveness of electricity transport versus hydrogen pipeline transport, a case study is presented which gives insight into the cost dynamics of these energy transmission vectors. Critically, this case study only considers the cost of the transport infrastructure and as such represents only partially the true levelized cost of hydrogen. This means that any hydrogen production equipment such as electrolyzers are excluded from the analysis. Nonetheless, this can give a future owner/operator of the transmission infrastructure insight into the levelized costs associated with both forms of energy transport, as a function of distance to shore and wind farm capacity.

When comparing the electrical transmission options with the transport by hydrogen pipeline, it will turn out as shown in the figure below that pipeline transport will be the most cost-effective option for any combination of distance to shore and wind farm capacity in this analysis.



This analysis only covers the (levelized) cost of the transport infrastructure, and therefore excludes the reality that installing and operating hydrogen production equipment offshore rather than onshore will be more expensive. Upon inclusion of these costs, DNV expects the cost-optimum to shift towards a situation where HVAC will be the most cost-effective transport option until 100 – 150 km from shore, based on earlier studies. Afterwards, hydrogen pipelines will take over and will be more cost-effective than HVDC transport for any combination of distance to shore and wind farm capacity in this analysis.

Total Green Hydrogen Potential from Offshore Wind

Considering the 100GW of installed offshore wind capacity, the total yearly electricity yield of ~312,000 GWh would be obtained based on a 35.65% average partial load factor. To calculate green hydrogen production, we distinguish three scenarios that account for specific factors that can lead to a loss of energy in the value chain such as distance to shore (transport efficiency) and electrolysis efficiency. The below table provides the value chain efficiency and corresponding annual green hydrogen production from 100GW of offshore wind.

Scenario	Value chain efficiency (% HHV)	Annual Hydrogen Production (H2/yr)
Low	60%	4.76 MMT
Base	68%	5.35 MMT
High	75%	5.95 MMT

Conclusion

With a conservative estimate of 5.35 million metric tons (MMT), the National Green Hydrogen Mission's target of 5 MMT can be easily achieved. Additionally, by considering the ambitious goal of exporting hydrogen via the sea route, the extra target of 5 MMT for exports can also be met. It's important to note that the initial projection of 5.35 MMT assumes a 100 gigawatt (GW) offshore potential, but the actual offshore wind potential exceeds this. The ESMAP-IFC's Offshore Wind Development Program estimates India's offshore wind potential at 174 GW (91 GW fixed and 83 GW floating), suggesting that hydrogen production could reach an impressive 10 MMT annually. Moreover, the potential for offshore wind energy is dynamic and expected to grow significantly as technology, especially in floating wind, advances. Additionally, the analysis highlights that hydrogen pipelines offer a more cost-effective solution than HVDC transport for varying distances to shore and wind farm capacities. Considering the immense scale and possibilities of green hydrogen production from offshore wind, it becomes clear that this opportunity cannot be overlooked. Therefore, the development of an integrated policy to harness this potential is absolutely essential.

1 INTRODUCTION

1.1 Context

In order to foster and deepen the dialogue surrounding the energy transition, the Indo-German Energy Forum (IGEF) was established by the German Chancellor and the Indian Prime Minister during the Hannover Fair in April 2006. The primary objective of the IGEF is to initiate strategic cooperation projects between the governments of Germany and India, as well as institutions and the private sector. Its overarching goals include promoting collaboration in energy security, energy efficiency (including energy conservation), renewable energy, investment in energy projects, and joint research and development in specific areas while taking into account the environmental challenges associated with sustainable development.

To assist India in its endeavour to become a global hub for Power-to-X (PtX) applications, the Indo-German Energy Forum Support Office (IGEF-SO) has been established. Its main responsibility is to provide support and guidance for the realization of this vision. Under the PtX Hub program, implemented by the IGEF-SO, strategic cooperation projects are being initiated between the German and Indian governments, research institutions, and the private sector. The aim is to accelerate the transition towards climate-neutral industries and economies by leveraging the potential of green hydrogen and its derivatives.

The PtX Hub program has been commissioned by the German Federal Ministry for Economic Affairs and Climate Action (BMWK). By fostering collaboration and knowledge exchange, this program seeks to drive the adoption of green hydrogen technologies, thereby facilitating the transformation toward a sustainable and carbon-neutral future.

1.2 Objectives

India's goal of achieving Net Zero emissions by 2070 necessitates the exploration of viable solutions to address the challenge of hard-to-abate sectors, which are difficult to electrify. While electrification and renewable energy sources can effectively curb emissions from fossil fuels by replacing them, the role of green hydrogen becomes crucial in attaining the Net Zero objective. Green hydrogen not only aids in curtailing emissions but also serves as a versatile energy carrier and storage medium. Recognizing its critical importance, the Indian Government has introduced the National Green Hydrogen Mission, aimed at establishing a comprehensive action plan and facilitating the development of a suitable ecosystem.

Under this mission, the objective is to build the necessary capabilities to produce a minimum of 5 Million Metric Tonnes (MMT) of green hydrogen per annum by 2030, with the potential to increase production to 10 MMT per annum to meet growing export market demands. Achieving this 10 MMT per annum target would require an additional 250GW of renewable energy capacity. Furthermore, as the government has already set a target of installing 500GW of non-fossil fuel-based electricity capacity by 2030, the requirement for renewable energy sources becomes substantial due to the need for electrification, electric mobility, green hydrogen production, and the year-on-year increase in demand resulting from population and economic growth.

In this context, offshore wind energy emerges as a significant proposition for renewable energy sources due to the absence of challenges related to land availability and acquisition. Moreover, the production of green hydrogen from offshore wind offers several advantages, including the availability of water (a vital input for green hydrogen production), suitability for export through sea routes, and proximity to consumption centres such as refineries, metal industries, and marine transport, which are predominantly located along the coast.

The potential of offshore wind in India was assessed by the FOWIND consortium, which identified favourable zones off the coasts of Gujarat and Tamil Nadu. With India boasting a vast coastline spanning over 7,000km and possessing rights to develop offshore wind resources up to a seaward distance of 200 nautical miles (Exclusive Economic Zone), offshore wind energy holds significant potential. However, uncertainties remain regarding the overall potential for green hydrogen production from offshore wind in India and the optimal design of offshore wind farms in conjunction with green hydrogen production. This study aims to address these questions and explore potential solutions.

2 OFFSHORE WIND

According to the International Energy Agency's Offshore Wind Outlook 2019, the potential of offshore wind energy is more than sufficient to meet the World's total electricity demand 11 times over by 2040. As of the end of 2022, the global installed capacity of offshore wind stands at 57.6 GW, as reported by the World Forum Offshore (WFO). Projections from DNV's Energy Transition Outlook indicate that by 2050, the installed capacity of offshore wind will reach an impressive 2,000 GW, contributing to approximately 15% of the world's electricity generation. This signifies a remarkable growth of offshore wind, with expectations for it to increase 35-fold over the next 27 years from its current capacity of 57 GW in 2022. The below plot provides estimates of year-on-year installation of offshore wind globally.

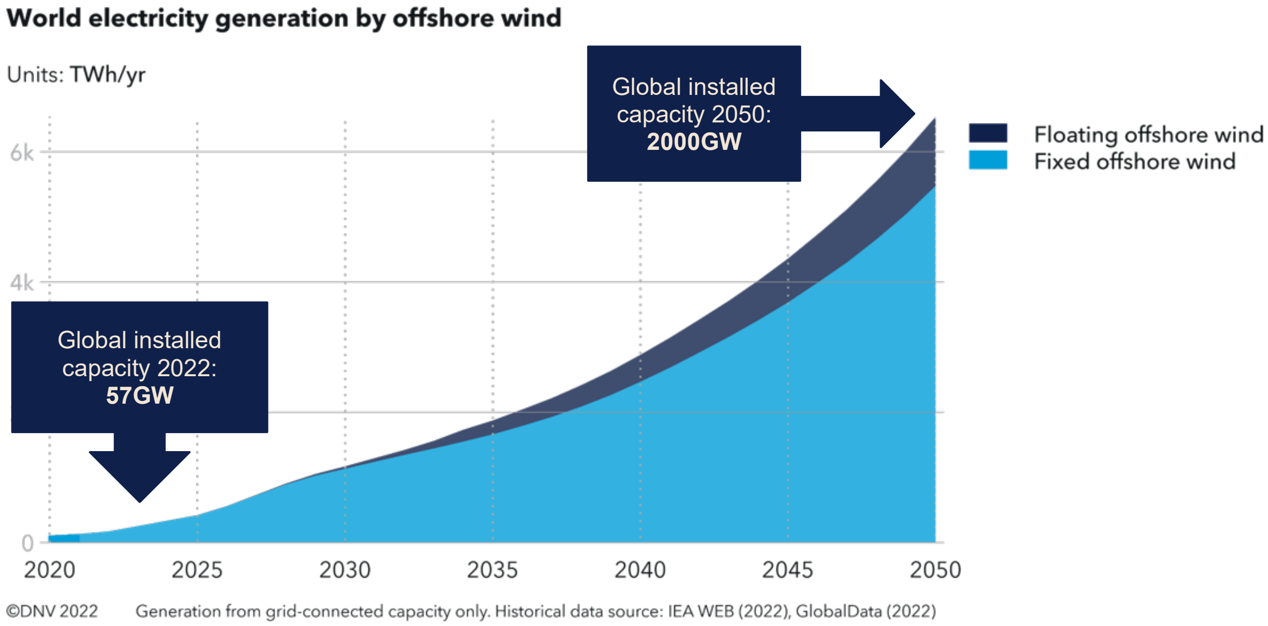


Figure 3-1 Offshore wind Installation forecast

2.1 Offshore Wind Project Cycle

The development of offshore wind is a complex process with the involvement of more than 100 agencies and requires careful planning and execution. The different phases and associated risks and timelines are shown in the figure below.

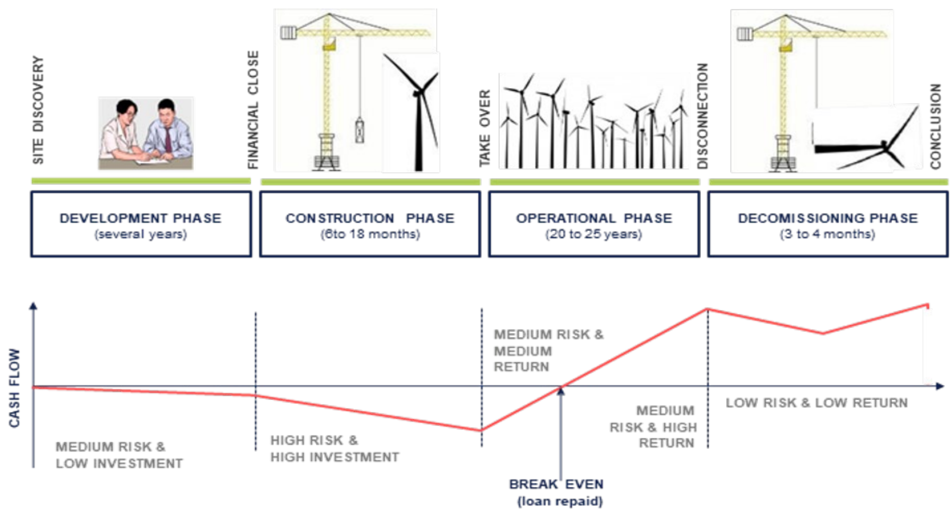


Figure 3-2 Offshore wind project development cycle

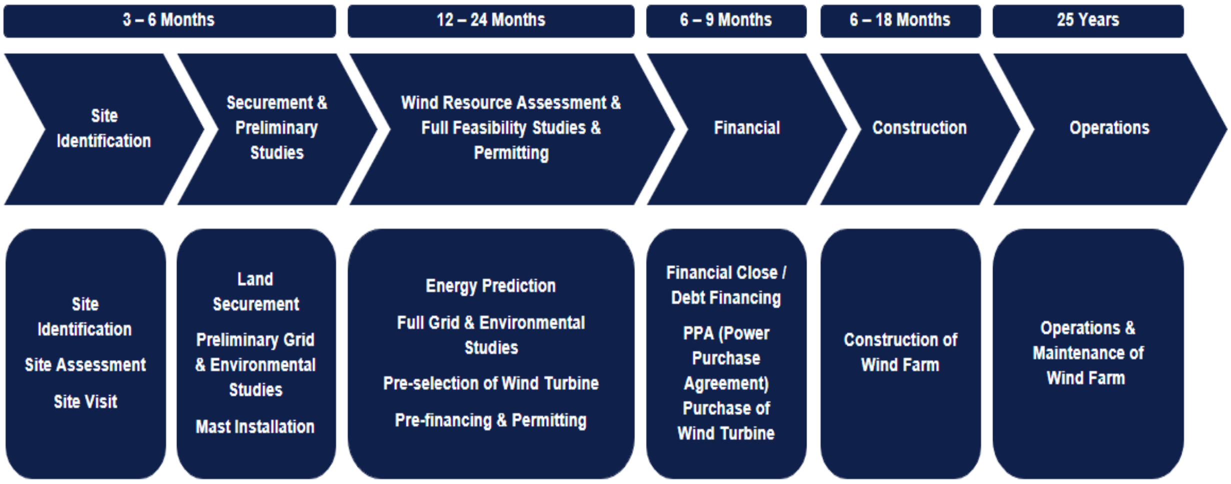


Figure 3-3 Detailed views of the Project development cycle

Development

The development phase of an offshore wind farm project typically begins with the identification of potential sites. This can be done by conducting wind resource assessments, environmental impact assessments, and seabed surveys. Once a potential site has been identified, a feasibility study is conducted to determine the economic and technical viability of the project. If the feasibility study is successful, the project developer will then need to obtain the necessary permits from the government. The development phase of an offshore wind farm project involves designing, engineering, and constructing the wind farm. This is a complex and challenging process that requires a significant amount of expertise. The design of the wind farm must take into account a wide range of factors, including the wind resource, the seabed conditions, the environmental impact, and the cost. The engineering of the wind farm must ensure that it is safe, reliable, and able to withstand the harsh conditions of the marine environment. The construction of the wind farm is a major undertaking that can take several years to complete.

Construction

The installation phase of an offshore wind farm project involves installing wind turbines, foundations, and other infrastructure. This is a complex and challenging process that requires the use of specialized equipment and vessels. The wind turbines are typically installed using jack-up vessels, while the foundations are installed using heavy lift vessels / jack-up rigs. The other infrastructure, such as the substation and the export cables, is installed using a variety of methods. The commissioning phase of an offshore wind farm project involves testing and commissioning the wind farm to ensure that it is operating as designed. This is a critical phase of the project, as it ensures that the wind farm is able to generate electricity and deliver it to the grid. The commissioning process typically involves a series of tests, including load testing, grid connection testing, and environmental monitoring.

O&M

The operation and maintenance (O&M) phase of an offshore wind farm project is the longest phase. This phase involves monitoring the wind farm and performing regular maintenance to ensure that it continues to operate reliably. The O&M activities typically include inspections, repairs, and replacements. The O&M costs for an offshore wind farm can be significant, so it is important to factor these costs into the project's overall economics.

Decommissioning

The decommissioning phase of an offshore wind farm project involves removing the wind farm at the end of its operational life. This is a complex and challenging process that requires careful planning and execution. The decommissioning process typically involves dismantling the wind turbines, removing the foundations, and disposing of the waste material. The decommissioning costs for an offshore wind farm can be significant, so it is important to factor these costs into the project's overall economics.

2.2 Offshore Wind Initiatives in India

India made strong commitments under the UN Paris Climate Agreement and in 2015 announced its renewable energy target for 175 GW from renewable energy generation by 2022. This target included 60 GW of wind energy. Even before this target, the Government was contemplating harnessing the offshore wind given the long coastline and huge potential. Because of the logistics challenges and issues around land acquisition, the industry has been exploring the possibility of offshore wind. The below table provides the key highlights in terms of major progress made in this direction.

Date	Projects/Milestones	Key highlights	Comments
2013-2018	FOWIND project	Zone selections, Pre-feasibility, and feasibility studies, supply chain and grid studies	The study was completed in March 2018
Oct 2015	National Offshore Wind Energy Policy	Provides a basic framework for the development of offshore areas within the Exclusive Economic Zone (200 Nautical Miles from the baseline) Responsibilities of various ministries and departments are defined for clearances of offshore projects	
2015-2018	FOWPI Project	Metocean data requirements, electrical concept design, and wind farm design off the coast of Gujarat	This project was mainly for the first proposed offshore wind project of 1GW in Gujarat.
Dec 2017	First Lidar in India for offshore wind measurement	Suzlon installed its first Operational Offshore LiDAR in the Kutch region of Gujarat.	No update available
Mar 2018	National Research & Test Centre for offshore wind to be set up in Tamil Nadu	6 turbines are to be installed.	Presently this project is still in the planning phase. One met mast of 120m would be installed.
Jun 2018	Offshore wind target by Govt.	MNRE announced a 30 GW offshore target by 2030 and 5 GW by 2022	
Nov 2018	Lidar installation in Gujarat by FOWIND	More than two years of measurement campaign at a site	
Dec 2018	First EoI for offshore wind for 1,000 MW in Gujarat was released by MNRE.	More than 35 Companies participated	
Jan 2019	MNRE releases Draft Offshore Wind Energy Lease Rules	Areas to be allocated via global competitive bidding only. The lease will be initially for 5 years for prospecting and 30 years for the establishment of offshore wind power projects.	
Apr 2019	India and Denmark entered into a cooperation agreement in the field of renewable energy with a focus on offshore wind.	An Indo-Danish Centre of Excellence for renewable energy in India is set up	This centre is undertaking offshore wind-related studies in India
May 2020	ONGC, NTPC sign MOU to set up a joint venture for renewable energy business	NTPC and ONGC will explore the setting up of offshore wind and other Renewable Energy Projects in India and overseas.	
2021	Four LiDARs are to be installed (one in Gujarat and three in Tamil Nadu) in 2021 by NIWE	The geotechnical investigation(Report not in the public domain yet) for zone B in Tamil Nadu for LiDAR is completed by NIWE. The support structure is designed and the tender for procurement & installation of LiDAR is in the process	There is a significant delay in the installation of Lidar

Date	Projects/Milestones	Key highlights	Comments
Jul 2022	MNRE released Strategy Paper for Establishment of Offshore Wind Energy Projects	Describes three models for the development of offshore wind and provides a timeline for tender of 37GW by March 2030.	
Nov 2022	MNRE released India's first-ever draft tender document for offshore wind	Circulated for stakeholder consultation. Based on this, a tender process will be undertaken to select developers for leasing of seabed areas equivalent to 4 GW of offshore wind power projects off the coast of Tamil Nadu under model 3 mentioned in a strategy paper	
Apr 2023	MNRE released a revised draft tender for offshore wind and a revised strategy paper for the establishment of offshore wind energy projects	The revised draft strategy paper has 4 different models of offshore wind development.	
Sep 2023	MNRE released Revision: 2 version Strategy Paper for Establishment of OSW projects	The Strategy paper has 3 models for OSW development. Indicative auction trajectory of 37 GW by 2030.	
Feb 2024	SECI invites bids for Allocation of Sea-bed Lease Rights for 4000 MW Offshore Wind Power Projects	The energy generated from the Project may be captively consumed or sold to third parties (including on a merchant basis or else on the exchange or to procurers on bilateral lease or by participating in bids for power procurement. MNRE/ NIWE or any other Government Agency shall not be obliged to buy any power generated from the Project.	
June 2024	On 19th June, 2024, the Union Cabinet approved the VGF scheme totalling Rs.7453 crs for Offshore Wind Energy.	The total outlay includes ₹6,853 crore for installing and commissioning 1 GW of offshore wind power (500 MW each in Gujarat and Tamil Nadu). Additionally, ₹600 crore for port upgrades (₹300 crore per state) is included in the VGF scheme to lower power costs for Discoms. A 25-year PPA will be provided by Discoms in both states. PGCIL will develop 2 GW offshore evacuation infrastructure under Regulated Tariff Mechanism (RTM), with an additional 4 GW through Tariff Based Competitive Bidding (TBCB), as per the 20th NCT meeting.	In a meeting on 14.06.2023, it was decided that PGCIL will develop 2 GW offshore wind evacuation infrastructure (1 GW each in Gujarat and Tamil Nadu) under RTM, with an additional 4 GW through Tariff Based Competitive Bidding (TBCB). The 500 MW offshore wind schemes for Gujarat (₹6,900 crore) and Tamil Nadu (₹6,242 crore) are expected by March 2029 and March 2030, respectively, recommended to PGCIL under RTM.
September - October 2024	Expected release by SECI of the 4GW Seabed Lease Tender for Offshore Wind Energy, offshore TN	SECI is expected to release a 4 GW seabed lease tender for offshore wind energy off the coast of Tamil Nadu. This tender aims to boost offshore wind development and contribute to India's renewable energy targets.	

2.2.1 Studies Prior to 2013

A number of agencies and institutions had assessed the offshore wind potential of the Indian coast including the coasts of Gujarat and Tamil Nadu. However, all of these studies were subject to various limitations with the possibility to draw various conclusions. Most of these studies were based on modeled data wherein the nature of uncertainty was higher. These wind data sets were available for 10 m or 50 m above sea level and were then extrapolated to 80 m or above. The temporal (e.g. diurnal, seasonal) and spatial variations in available wind data sets used for these studies were inadequate for dependable resource assessment. Further, the studies do not take into consideration spatial constraints and oceanographic conditions for potential offshore wind regions. The first comprehensive study related to offshore wind in India was FOWIND Project which is described in the next section.

2.2.2 FOWIND Project

Facilitating Offshore Wind in India (FOWIND) was a project largely funded by European Union and led by GWEC between December 2013 and March 2018. DNV was the technical partner in the consortium. The objective of this four-year project was to provide feasibility studies, knowledge-sharing workshops/seminars and offshore wind measurement to support India in its development of a commercial offshore wind market. The project focused on the states of Gujarat and Tamil Nadu to identify potential zones of development through preliminary resource and feasibility assessments for future offshore wind developments, as well as through techno-commercial analysis and preliminary resource assessment.

It also established a platform for structural collaboration and knowledge sharing between stakeholders from European Union and India, on offshore wind technology, policy, regulation, industry and human resource development. FOWIND activities also helped facilitate a platform to stimulate offshore wind-related R&D activities in the country.

As the project's technical partner, DNV has fruitfully leveraged its offshore wind and local market expertise from international teams, including India (Bangalore), the UK, Singapore, Canada, the USA and Australia. These capabilities have facilitated the delivery of technically rigorous milestone reports (see below report titles with links) that are enabling the Government of India and its stakeholders to bring this new offshore wind market closer to fruition:

- Offshore Wind Policy and Market Assessment Report (delivered 2014)
- Pre-feasibility Offshore Wind Farm Development in Gujarat and Tamil Nadu (delivered 2015)
- Supply chain, port infrastructure and logistics study (delivered 2016)
- Grid Connection and Transmission Assessment (delivered 2017)
- "From zero to five GW – Offshore Wind Outlook for Gujarat and Tamil Nadu 2018-2032" report (delivered 2017)
- Feasibility Studies for Offshore Wind Development in Gujarat and Tamil Nadu (delivered March 2018)

Based on the preliminary assessment from satellite data and data available from other sources, eight zones each in Gujarat and Tamil Nadu have been identified as potential offshore zones for exploitation of offshore wind energy. Initial assessment by NIWE within the identified zones suggested 36 GW of offshore wind energy potential exists off the coast of Gujarat only. Further, nearly 35 GW of offshore wind energy potential exists off the Tamil Nadu coast.

The FOWIND feasibility reports aimed to provide a concept design for a 150 to 504 MW demonstration project in both Gujarat's and Tamil Nadu's most promising offshore wind development areas. These were identified as "zone A" in the pre-feasibility Studies. This provides companies and government institutions with a starting point for future detailed offshore front-end engineering design (FEED) studies and assists with the identification of key project risks in the states of Gujarat and Tamil Nadu.

LiDAR installation in Gujarat

LiDAR was commissioned by FOWIND in November 2017 for Offshore Wind Resource assessment in identified Zone-B off the coast of Gujarat nearly 25 km away from the port of Pipavav and collection of data started since then. Two years of data collected from the deployed LiDAR has been analysed and the report is published by NIWE. As per the report, the annual average wind speed at the locations is observed to be around 7.5 m/s at 100 m hub height. Further, it is planned to install additional five LiDARs (two for Gujarat and three for Tamil Nadu). The purpose of LiDAR installations is to undertake ground-based wind measurements in order to make the wind resource assessment bankable.

2.2.3 FOWPI Project

FOWPI was another project started in December 2015 by European Union with the objective to provide assistance up to the stage of Pre-Financial-Investment-Decision (Pre-FiT) and provide general assistance for capacity building of Indian stakeholders within the offshore wind sector. FOWPI studies primarily included met ocean data requirements, weather windows for installation, electrical concept design, and wind farm design layout optimization along with economic considerations. The report on "Wind Turbine, Layout and AEP" has been prepared during FOWPI with the purpose of providing preliminary design and annual energy production estimates for the prospected 200 MW initially and later updated with 1000 MW FOWPI offshore wind farm (OWF) near the coast of Gujarat.

2.2.4 National Test Centre for Offshore Wind

NIWE has proposed National Test Centre for Offshore Wind Turbines as a Research Station at Dhanushkodi, Rameswaram in Tamil Nadu for which 75 acres of land has been allotted. The proposed research 'test field' would consist of 4-5 turbines with a minimum rated power of 6 MW preferably higher than 8 MW. The initial proposed turbine locations are near the existing Dhanushkodi met mast. Based on met mast measurements at Dhanushkodi, the annual mean wind speed at 102 m is approximately 8.65 m/s measured between 2013-17. It is understood that test beds will be created for testing of these proposed offshore wind turbines in Dhanushkodi. It is recommended that Government may consider including the test bed for the production of green hydrogen as well.

This is envisaged to be a demonstration facility along the lines of the Danish site at Østerild. For testing of offshore wind turbines, land-based installation is generally preferred by the OEMs as this enables permanent direct access for technicians to perform any component replacements as well as maintenance and service activities during testing as compared to access at sea which can lead to added complexities and longer durations. In the initial power evacuation plan, NIWE has proposed two 33 kV cable routes from the turbines to the Mandapam substation. For the first route, the upgradation of the existing Rameshwaram substation is a proposed solution. Alternatively, a new pooling station located about 18.5 km from wind turbines has also been proposed.

2.2.5 Potential for Future Developments

In October 2019, the World Bank Group published a report on "Expanding Offshore Wind to Emerging Markets". The report indicates that the technical potential for offshore wind in India within 200 km is 112 GW and 83 GW for fixed and floating offshore wind concepts respectively. The report also includes a technical potential map for offshore wind in India which shows a mesoscale wind speed map along with fixed (water depth < 50 m) and floating (water depth < 1000 m) technology zone boundaries within the EEZ of India.

As per the report, the best offshore wind resources are at the southern tip of India in Tamil Nadu. There is a sizeable shallow area which has a technical potential of 54 GW. In the northwest, off Gujarat in the Gulf of Khambhat, there is an area with weak winds between 7 and 7.25 m/s in waters less than 50 m deep. The technical potential is estimated to be 36 GW in line with NIWE estimates. A third wind area is north in the Gulf of Kutch with wind speeds of 7 to 7.25 m/s and shallow water. The technical potential for this area is 5 GW.

In terms of transmission systems, the grid near the southern tip of Tamil Nadu is 400 kilovolts (kV), which is suitable for large-scale offshore wind. It is also learned that there are plans to extend the nearby 765 kV line to Bangalore, creating a connection with a substantial demand centre.

Gujarat's grid is less robust near the coast, though it is understood that the Gujarat Energy Transmission Corporation has planned reinforcement to 400 kV to facilitate the initial 1 GW offshore wind project.

2.2.6 National Offshore Wind Energy Policy-2015

Indian Government released the National Offshore Wind Energy Policy in September 2015. The major objective of the policy is to promote the deployment of offshore wind farms in the Exclusive Economic Zone (EEZ) of the country i.e. up to 200nm from the baseline. The key points of the policy are as below:

- Ministry of New and Renewable Energy (MNRE) will be the Nodal Ministry and will have major responsibilities like overall monitoring, coordination with other ministries, issuing guidelines/directives for offshore wind development in India
- The National Institute of Wind Energy (NIWE) will act as the Nodal agency and will have major responsibilities such as calling competitive bidding, entering into contracts with project developers, collecting leases, and facilitating project developers in getting clearances from concerned ministries/departments.
- NIWE will take in-principle clearance from the Ministry of Defence, Home, External Affairs, Environment & Forests and Department of Scape before notifying the blocks for competitive bidding (stage-I clearance). On allocation of the block, the successful bidder/developer will have to take clearance/NOCs from central and state ministries/departments (stage-II clearance). Refer to the table below for stage 1 and II clearances.
- The policy provides a list of ministries and departments from who a clearance or a NOC will be required for surveys & studies and development of offshore wind projects.
- Bundling schemes with power from other sources and centralised procurement may be introduced as and when required for the promotion of offshore wind development.
- The Central Government may provide support to state governments in the creation of evacuation infrastructure for offshore wind projects. Central and State Transmission Utilities will provide the necessary onshore infrastructure for evacuating the power generated by offshore wind farms.

The policy mentions that NIWE will accept applications for clearance/NOC from the project developers and coordinate with concerned ministries/departments. The developer is required to directly apply for clearances/approval from the concerned state governments. The policy mentions that a clear time schedule for approval, clearance and NOCs will be issued by MNRE separately. However, no such time schedule has been issued till date.

The policy mentions that the Government may support through fiscal incentives, allowing FDI participation, Public Private Partnership and international collaboration. However, policy or any directive from Government hasn't come up with any financial incentive yet.

Table 3-1 List of clearance in Stages 1 & 2

Sl. No.	Ministry/Department	Stage-1 Clearances	Stage-2 Clearances (or NoCs)
1.	Ministry of Environment & Forests	In-Principle Clearance	EIA & CRZ Clearance
2.	Ministry of Defence	In-Principle Clearance	Clearance related to defence & security aspects, related to the army, Navy, Air Force, DRDO and other such institutions under MoD.
3.	Ministry of External Affairs	In-Principle Clearance	Clearance for the development of offshore wind energy projects within the maritime zones of India.
4.	Ministry of Home Affairs	In-Principle Clearance	Clearance regarding deployment of foreign nationals in offshore wind energy block
5.	Ministry of Civil Aviation	No clearance is needed at this stage	Clearance for construction near aviation radars/aerodromes. No clearance/NOC is required for all other locations.
6.	Ministry of Petroleum & natural gas	No clearance is needed at this stage	Clearance for the project near major ports. No objections certificate to operate away from shipping lanes.

7.	Ministry of shipping	No clearance is needed at this stage	Clearance for the project near Major ports. No objection certificate to operate away from shipping lanes
8.	Department of Space	In-Principle Clearance	Clearance from a security angle with regard to Dept of Space Installation and for minimum safety distance to be maintained from the Dept of Space installations.
9.	Department of Telecommunication	No clearance is needed at this stage	No objection certificate to operate outside subsea communication cable zones.
10.	Ministry of Mines	No clearance is needed at this stage	No objection certificate to operate outside mining Zones.

2.2.7 Strategy Paper and Recommendations

In July 2022, MNRE published the "Strategy Paper for Establishment of Offshore Wind Energy Projects" which outlined the three different models of establishing offshore wind in India. In April 2023, MNRE released the first draft version of the revised strategy paper. In September 2023, Ministry has issued the revised strategy. As per the revised version, the following three models are proposed for the holistic development of offshore wind farms:

- **Model-A (VGF Model):** This approach will be followed for demarcated offshore wind zones for which MNRE/NIWE has carried out or proposed to carry out detailed studies/surveys. Presently, part of identified Zone B3 (365 Sq.km) equivalent to 0.5 GW off the coast of Gujarat and 0.5 GW equivalent site off TN coast will be considered in phase-1 of this model. MNRE through its implementing agencies will come up with bid for procurement of offshore wind power capacity under this model. Necessary central financial assistance in the form of Viability Gap Funding (VGF) would be available to achieve a predetermined power tariff.
- **Model- B (**(Non-VGF but with exclusivity over seabed during the study/survey period)::. This approach will be followed for sites identified by NIWE. Proposed offshore wind sites demarcated within identified zones would be allocated for a fixed period on a lease basis through single-stage two envelope bidding. Project development shall be carried out by the prospective developer in these sites without any Central Financial Assistance (CFA). The power generated from such projects shall be either used for captive consumption under open access mechanism or sold to any entity through a bilateral power purchase agreement or y period) sold through Power Exchanges. Government may also call for bids for procurement of power for DISCOMs on the basis of tariff after two years. Benefits like provision of power evacuation infrastructure from the off shore pooling delivery point, waiver of transmission charge and additional surcharge, Renewable Energy Credits with Multipliers, Carbon Credit benefits etc. as determined by GoI/ State Govt's from time to time shall be applicable.
- **Model-C** (Non-VGF and without exclusivity over seabed during the study/survey period)**:** In this model, Developer may identify any offshore wind site within the EEZ excluding the sites considered under Model A and Model B , and carry out studies and surveys. The Government will come up with bid for project development/allocation of the seabed. The bidding may include any one of the following methods.
    - Bidding on lease/allocation fee or revenue sharing in case of projects for captive consumption/third party sale/sale through an exchange under open access mechanism.
    - Tariff-based competitive bidding in case of power procurement by DISCOMs or Central Govt. or State Govt.
    - Any other transparent bidding mechanism identified by the Government.

Government of India may also designate any Central/state Government/agency to carry out the bidding on its behalf wherein the concerned state government/agency assures the power offtake from the proposed offshore wind project.

The developer who has conducted the study/survey of respective sites may also submit the proposal for project development and allocation of offshore sites under this model. In this case, site specific bidding would be conducted with a first right of refusal to the developer who had conducted study/survey. However, Project development shall be carried out by the prospective developer in this zone without any Central Financial Assistance (CFA). Benefits like provision of power evacuation infrastructure from the off shore connecting point, waiver of transmission charges, Renewable Energy Credits with Multipliers, Carbon Credit benefits etc. as determined by GoI/ State Govt's from time to time shall be applicable.

Table below describes the financial year-wise indicative auction size to be floated under each of the three different models. As can be seen, Indian Government has the ambitious target of floating 37GW of tender until March 2030.

Year	Auction Capacity under Model-A (in GW)	Auction Capacity under Model-B (in GW)	Auction Capacity under Model-C (in GW)	Total Auction Trajectory (in GW)
2023-24	0.5	4	-	4.5
2024-25	0.5	3	-	3.5
2025-26	-	3	4	7
2026-27	-	3	4	7
2027-28	-	1	4	5
2028-29	-	-	5	5
2029-30	-	-	5	5
Total	1	14	22	37

Table: Offshore wind Auction strategy under various models till 2030

The main characteristics of each of the different models in terms of off-taker, seabed exclusivity, viability gap funding (VGF) and award criteria are tabulated below.

Figure 2-4
Table 2-2 Auction Models Comparison

Features	Model A	Model B	Model C
Offtake	Govt Discom	open access/captive/third party sale	Open access/Got. DISCOM
Seabed exclusivity	Yes	Yes, during study/survey period	No
VGF	Available	Not Available	Not available
Transmission Infra	Evacuation of Power from Offshore Wind farm to OFFSHORE Sub-Station is in the scope of the Developer under Model A and B. ONLY under Model C the Evacuation of Power from the Offshore Wind Farm to the Onshore Sub- Station is the responsibility and in the scope of work of the Developer		
Award criteria	single bid two-stage process followed by an e-Reverse Auction	single-stage two-envelope bidding	First come first serve basis for survey/studies; Bidding on lease/allocation fee or revenue sharing in case of projects for captive consumption/third party sale or tariff-based competitive

			bidding in case of power procurement by State DISCOMs.
Zones	Zone B3 of Gujarat and 0.5 GW equivalent site off TN coast	Zones B,D, E and G of Tamil Nadu	any site within the EEZ excluding the sites considered under Model A, and Model-B
Capacity	1 GW	15.34 – 20.45 GW	Capacity not defined

It can be inferred from the table above that:

- VGF is available for model A where the off-taker is Government owned Discom. This corresponds to 0.5 GW in Gujarat and 0.5 GW in Tamil Nadu. So, VGF would be available for these 1 GW capacities only.
- Models B and Care for open access where it is either used for captive consumption or sold to any entity through a bilateral power purchase agreement or sold through Power Exchanges. However, no VGF would be provided.
- Benefits like provision of power evacuation infrastructure from the offshore connecting point, waiver of transmission charges, renewable energy credits with multipliers, carbon credit benefits etc. as determined by GoI/ State Govt from time to time shall be applicable for models B & C. However, such benefits are yet to be announced.

2.2.7.1 Recommendations

The Indian government's initiatives for offshore wind and the accompanying strategy paper primarily focus on utilizing offshore wind for electricity generation, without integrating hydrogen production. However, it is important to note that Models B & C allow for open access to electricity, which can also be utilized for hydrogen production. Unfortunately, there is currently no availability of viability gap funding for these models. Additionally, the revised strategy paper now places the responsibility of power evacuation up to the onshore meeting/interconnection point on the developer, whereas it was previously the responsibility of the Central Transmission Utility. Developers are advocating for the compensation of power evacuation infrastructure development by the CTU/Ministry, as this would provide significant support from the central government. In light of these circumstances, the following points should be considered regarding hydrogen production from offshore wind in India:

a) Models B & C are considered suitable for utilizing offshore wind for hydrogen production.

b) If the government agrees to compensate for the cost of power evacuation, it would make onshore hydrogen production more attractive to developers compared to offshore centralized and decentralized hydrogen production.

c) There is a benefit of the Inter-State Transmission System (ISTS) applicable to projects commissioned until December 31, 2032. Essentially, there are no wheeling charges for electricity transported through the ISTS. This means that developers can establish hydrogen production plants closer to the point of consumption, eliminating the need for hydrogen transportation. However, it is worth noting that other renewable sources like onshore wind and solar would be relatively cheaper options for hydrogen production compared to offshore wind.

d) Under the National Green Hydrogen Mission, there are plans to provide incentives (expected to be 10% of the cost) to green hydrogen fuel producers through a $2 billion scheme. Producers of hydrogen from offshore wind could potentially claim these incentives. However, it is important to mention that these incentives are currently available for hydrogen production from onshore wind and solar, making offshore wind a more expensive option for hydrogen production compared to other renewable sources.

e) Given the significant renewable energy requirements in India, including 500 GW of end-use electricity by 2030, production of at least 5 MMT of Green Hydrogen per annum by 2030 (with potential for 10 MMT per annum with export market growth), and additional renewable capacity for the electrification target of 30% of the vehicle fleet by 2030, offshore wind will play a crucial role. Therefore, the government should formulate an exclusive policy for hydrogen production from offshore wind, carefully considering the pros and cons of the three different energy vector options described in the relevant sections in this report.

In summary, while offshore wind presents opportunities for hydrogen production, such as with Models B & C and the benefits of the ISTS, challenges remain, including the cost of power evacuation and the availability of incentives. The government need to develop a comprehensive policy specifically addressing hydrogen production from offshore wind, taking into account its unique characteristics and potential.

2.2.8 Additional Studies

This section describes the additional studies/surveys required for the development of offshore wind farms & hydrogen production. The below table provides the additional studies along with descriptions, agencies and example costs in the European market. The list of agencies included is not exhaustive and is indicative only.

Additional studies	Description	Agencies	Example costs in UK/European market (in €) [1]
Resource and metocean assessment	Resource and metocean assessments are carried out to provide atmospheric and oceanographic datasets to inform the engineering design of a wind farm, and the potential future energy production, and to fully describe the likely operating conditions at the proposed wind farm location. • Structure: The structure provides the mounting for the meteorological and metocean, sensors, and auxiliary systems plus safe access for personnel. • Sensors: Sensors provide data on meteorological and oceanographic conditions at the site of interest. Data loggers provide data storage, processing and remote communications capability. • Maintenance: Offshore wind and metocean systems will require maintenance, including inspection, cleaning and refuelling (where diesel generators or hydrogen fuel cells or similar are used).	Resource campaign management and design: Deutsche Windtechnik, DNV, Fugro, K2 Management, Natural Power (Fred. Olsen) and Oldbaum Services. Foundation and Platform: Bladt Industries, Sif and Smulders. Masts: FLI Structures, Fugro, MT Højgaard and Sembmarine. Floating lidar systems: Axys, Babcock, EOLFI, EOLOS, Fraunhofer and Fugro. Metocean campaigns and buoys: Axys, Fugro, Partrac Gardline, and Intertek Meteorological sensors: FT Technologies, Gill Instruments, Kipp & Zonen, NRG Systems, Orga, Thies, Vaisala and Vector Instruments. Wind lidars: Leosphere (Vaisala), Wood and ZX Lidars (Fred. Olsen). Metocean sensors: Datawell, SonTek. Data loggers: Campbell Scientific. System maintenance is typically undertaken by the original system supplier, who will charter vessels for the purpose. Other providers of system maintenance include Deutsche Windtechnik, Dulas and Wood.	Costs for resource and metocean assessment are about €4.6 million for a 1 GW offshore wind farm, assuming no met mast platform is installed. Example costs for elements of this include: • Floating lidar: €430,000 • Lidar mounted on an existing platform: €230,000 • Met masts and platform: €5.75 million to 11.5 million • Metocean buoy: €200,000, and • Wave radar: €115,000.

Additional studies	Description	Agencies	Example costs in UK/European market (in €) [1]
Detailed typhoon assessments	IEC 61400-1: 2019 Edition 4 recommends that in regions prone to hurricanes, cyclones and typhoons, the extreme wind speed shall be evaluated by the Monte Carlo simulation (MCS) method. It is recommended to perform a detailed analysis of the chosen site location(s) to consider the risk that cyclones could take a different path in the future.	DNV: MCS evaluations by DNV were accepted through the full certification process in 2019, for two large offshore wind farms in Taiwan. Other consultants: COWI, Vaisala, UL Renewables, Ramboll, Wood Group, TÜV SÜD	About €20,000 for one 1GW wind farm site
Geological and hydrographical surveys	Seabed surveys analyse the sub-seabed environment of the proposed wind farm site and export cable route to assess its geological condition and engineering characteristics. The data collected is utilised in a wide range of engineering and environmental studies through the design and development phase.	Fugro, G-tec, Gardline, Intertek and Horizon	About €4.6 million for a 1GW wind farm.
Geophysical and Hydrographic surveys	Geophysical surveys establish seafloor bathymetry, seabed features, water depth and soil stratigraphy, as well as identify hazardous areas on the seafloor and manmade risks such as unexploded ordnance (UXO). Specialist vessels can be used to carry out geophysical surveys of the seabed. Hydrographic surveys examine the impact of wind farm development on local sedimentation and coastal processes such as erosion. This is often part of the geophysical survey. These surveys are also part of the post-construction monitoring during the operations phase.	Nortek, Plant Ocean, Bibby HydroMap, Fugro, Gardline, Horizon and MMT. Consultants such as ABPmer and HR Wallingford undertake the impact modelling.	About €805,000 for a 1GW wind farm. About €920,000 for a 1GW wind farm for hydrographic surveys
Geotechnical surveys	Geotechnical site investigations are conducted following the geophysical survey to use the information obtained to target soil/rock strata boundaries and engineering properties or specific seafloor features. Specialist vessels carry out geotechnical surveys of the seabed.	Fugro, G-tec, Gardline, Intertek and Horizon	About €2.9 million for a 1GW wind farm.

Additional studies	Description	Agencies	Example costs in UK/European market (in €) [1]
Environmental impact assessments	• Benthic environmental surveys: • Fish and shellfish surveys: • Ornithological environmental surveys: • Marine mammal environmental surveys: • Onshore environmental surveys: • Human impact studies:	EIA suppliers include AECOM, Arcus, ERM, GoBe, Intertek, Natural Power (Fred. Olsen), Royal Haskoning, NIRAS, RPS and SLR. Benthic environmental surveys: ABPmer, APEM, Fugro, Gardline and Natural Power (Fred. Olsen) Fish and shellfish surveys: ABPmer, APEM, Fugro, Gardline, Natural Power (Fred. Olsen) and Precision Marine Ornithological environmental surveys: APEM, ECON, ESS Ecology, HiDef Aerial Surveying, Natural Power (Fred. Olsen) and RPS. Marine mammal environmental surveys: ABPmer, APEM, Cork Ecology, ECON, ESS Ecology, Fugro, Gardline, HiDef Aerial Surveying, Natural Power (Fred. Olsen) and RPS. Onshore environmental surveys: Andrew McCarthy Associates, APEM, BCM Environs, ESS Ecology, Natural Power (Fred. Olsen), RSK Environment and Thomson Ecology. Human impact studies: Arcus, Hayes Mackenzie, Hoare Lea, LUC, Royal Haskoning, RPS and SLR. Offshore ornithological and mammal surveying Vessels: Bay Marine, Enviro-serve, Fugro, Gardline and Ocean Marine Services. Aircraft (including, but not limited to): APEM, HiDef Surveying.	About €9.2 million for a 1GW wind farm. Example costs for elements of this include: • Environmental surveys: About €4.6 million for a 1GW wind farm. • Benthic environmental surveys: About €520,000 for a 1GW wind farm. • Fish and shellfish surveys: About €460,000 for a 1GW wind farm. • Ornithological environmental surveys: About €1.5 million for a 1GW wind farm. • Marine mammal environmental surveys: About €1.5 million for a 1GW wind farm. • Onshore environmental surveys: About €635,000 for a typical 1GW wind farm. • Human impact studies: About €405,000 for a 1GW offshore wind farm.

Below are the additional studies required for Electrolysis:

1. **Grid Connected Electrolysis**: The scenarios considered in the report form the basis of a high-level assessment to compare basic types of hydrogen value chains. The onshore centralized scenarios are assumed to exist in isolation from the mainland electrical grid. However, further analysis (beyond the scope of this study) may also consider grid-connected scenarios, where import and export of power from the grid, or supplementation with a behind-the-meter solar farm, can be used to complement offshore wind power. The grid connectivity dynamics and evaluation of the feasibility of a grid-connected project are beyond the scope of this study and would also require analysis on an hourly basis across the project lifetime to assess the potential benefits grid connectivity could bring, in conjunction with the additional grid connection costs required. The

grid-connected concept introduces other complexities, such as how to certify (and what scheme will be used) to ensure that hydrogen is made only from 'green' electrons. Furthermore, being grid-connected may subject the hydrogen production plant to more stringent electrical design requirements to comply with the grid operator rules. This can have significant cost implications for the electrolyser power electronics aspects, which can make up around 25% of the overall electrolyser system cost, depending on the technology selected. The typicality Cost of these studies ranges from 80-100 K Euro per wind farm.

2. **Electrolyser Sizing Optimization**: The fact that the stack replacement is triggered with less than 1/3rd of the project lifetime remaining is an indication that additional optimisation can be performed in sizing the electrolyser stacks. For the onshore centralized case, downsizing the hydrogen plant results in a non-linear increase in the number of full-load hours of the electrolyser, triggering earlier degradation (optimally near ½ of the project lifetime). For the offshore cases with no access to a grid, balancing with Battery Energy Storage Systems (BESS) and/or hydrogen fuel cells (plus storage) will need to be undertaken in case of a <100% sizing of the electrolyser with respect to the wind generation capacity. This optimisation can be performed in a future study. The typicality Cost of these studies ranges from 50-70 K Euro per wind farm.

3. **Hydrogen Storage Optimization**: Often, industrial offtakes require a (near) flat delivery profile. In order to achieve this, large-scale hydrogen storage is needed to buffer the differences between supply and demand. A first estimate of hydrogen storage requirement is generated by taking the hourly generation profile for the wind farm and calculating the minimum storage size that would be required to deliver the average hourly production for all hours in the year, the storage acts as a buffer between supply (varying) and demand (constant). Please note that no hydrogen storage has been included in the cost modelling. This analysis can be performed in a future study.

2.2.9 Logistics: Procurement and Installation

The development of an offshore wind farm from design to fabrication to installation and through to operation is a complex puzzle with an extensive supply chain containing multiple interfaces. For the sake of simplicity, offshore wind development has been split into 5 phases as shown below.

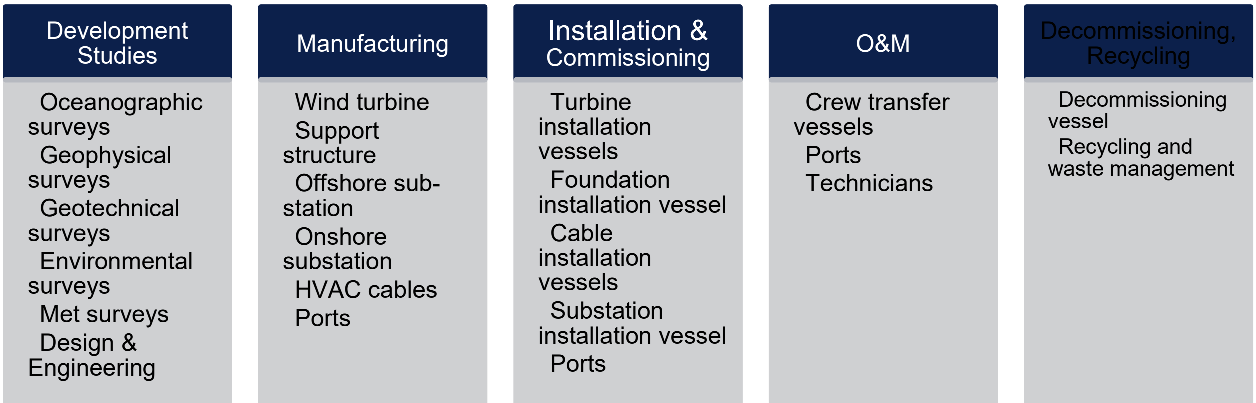


Figure 3-5 Offshore wind development phases

Logistics required for each phase are different and depend on the size, capacity, environmental, geotechnical and geophysical conditions. A full list of logistics would be very extensive and hence a representative list of only procurement and installation vessels are provided below.

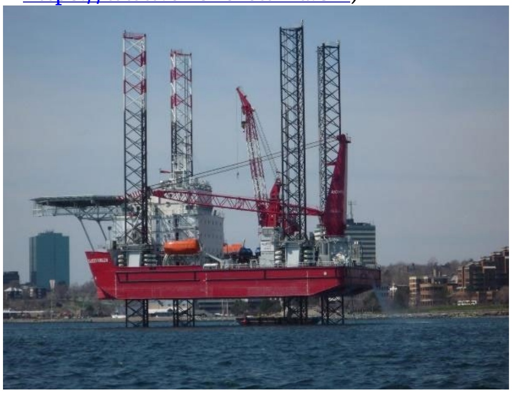
Table 3-3 Different Types of vessels used in offshore wind farm installation

Vessel Type	Installation element	Example Image	Summary specifications
Large jack-up vessel	Wind turbine installation	1. Seajacks Scylla (Source: https://www.offshorewind.biz)  2. Fred. Olsen Windcarrier Brave Tern (New Crane) (Source: https://www.offshorewind.biz)  3. Jan De Nul Voltaire (Source: https://www.offshore-energy.biz)  4. DEME Innovation (Source: https://www.deme-group.com) 	1. Seajacks Scylla Length = 139 m Beam = 50 m Draft laden = 6 m Air draft = 5 m (hull) Lift capacity = 1500 t at 15-31.5 m radii 2. Fred. Olsen Windcarrier Brave Tern (New Crane) Length = 132 m Beam = 45 m Draft laden = 4.25 to 5.5 m Air draft = 3.5 to 4.75 m (hull) Lift capacity = Long mode: 1250 t at 38.5 m outreach, lifting height 155 m. Max. lifting height 158.7 m at min. radius (New crane upgrade expected by 2022.) 3. Jan De Nul Voltaire Length = 169.3 m (181.78 m including helideck) Beam = 60 m Draft laden = 7.5 m (Maximum) Air draft =7.1 m (Moulded) Lift capacity = >3000 t (Maximum) at a lifting height of 162.5 m above the deck (This vessel is under construction at Cosco Shipping Shipyard in Nantong, China and keel laying was completed for the vessel in 2021.) 4. DEME Innovation Length = 147.5 m Beam = 42 m Draft laden = Approximately 7.3 m (Operating max) Air draft = 3.7 m (hull) Lift capacity = 1500 t (It is expected that this vessel would need to be jacked up during installation to meet the crane under hook height requirement during nacelle installation hence maximum lifting height is recommended to be confirmed for suitability of the vessel for the proposed turbine hub heights.)

Table 3-3 Different Types of vessels used in offshore wind farm installation

Vessel Type	Installation element	Example Image	Summary specifications
Heavy lift vessel	Monopile installation, Jacket structure installation, Offshore substation pin piles, jacket structure and topsides installation	1. Boskalis Bokalift 1 (Source: https://www.bakkersliedrecht.com)  2. Boskalis Bokalift 2 (Source: https://www.offshore-mag.com)  3. Seaway Strashnov (Renamed from Oleg Strashnov in 2019) (Source: https://www.bakkersliedrecht.com)  4. Seaway Yudin (Renamed from Stanislav Yudin in 2019) (Source: https://www.offshorewind.biz) 	1. Boskalis Bokalift 1 Length = 216 m Beam = 43 m Draft laden = 8.0-9.0 m Air draft = 4-5 m (moulded) Lift capacity = 3000 t 2. Boskalis Bokalift 2 Lift capacity = 4000 t (Vessel is under construction as of 2020 at Dubai's Drydocks World shipyard.) 3. Seaway Strashnov Length = 183 m Beam = 47 m Draft laden = 8.5-13.5 m Air draft = 4.7-9.7 m (deck) Lift capacity = 5000 t at 32 m with a maximum lift height of 102 m above water level 4. Seaway Yudin Length = 183 m Beam = 36 m Draft laden = 5.5-8.9 m Air draft = 4.1-7.5 m (deck) Lift capacity = 2500 t with a maximum lift height of 78.04 m above water level

Table 3-3 Different Types of vessels used in offshore wind farm installation

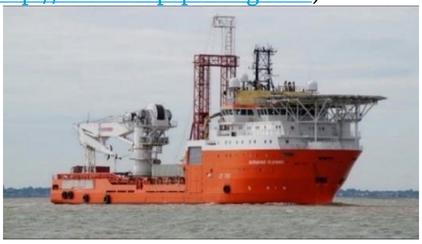
<table>
<tr><th>Vessel Type</th><th>Installation element</th><th>Example Image</th><th>Summary specifications</th></tr>
<tr>
<td>Small jack-up vessel</td>
<td>Jacket foundation pin-pile installation</td>
<td>1. Seajacks Kraken (Source: https://www.offshorewind.biz)

2. Seajacks Leviathan (Source: http://www.shipspotting.com)

3. Van Oord MPI Resolution (acquired from MPI Offshore in 2018) (Source: https://www.mpi-offshore.com)
</td>
<td>1. Seajacks Kraken
Length = 75 m (including helideck)
Beam = 36 m
Draft laden = 3.71 m
Air draft = 2.29 m (hull)
Lift capacity = 300 t (without boom extension)

2. Seajacks Leviathan
Length = 75 m (including helideck)
Beam = 36 m
Draft laden = 3.71 m
Air draft = 2.29 m (hull)
Lift capacity = 400 t at 18.5 m-main hoist (8 falls)

3. Van Oord MPI Resolution
Length = 130 m
Beam = 38 m
Draft laden = 4.3 m (Maximum for scantling)
Air draft = 3.7 m (main deck)
Lift capacity = 600 t at 25.0 m radius</td>
</tr>
</table>

Table 3-3 Different Types of vessels used in offshore wind farm installation

Vessel Type	Installation element	Example Image	Summary specifications
Oil & gas Offshore Supply Vessel (OSV)	Array cable installation	1. Normand Flower (Source: http://www.shipspotting.com)  2. Normand Mermaid (Source: https://ulstein.com) 	1. Normand Flower Length = 93.1 m Beam = 21.5 m Draft laden = 6.3 m (maximum) Lift capacity = 150 t @ 10 m (maximum 35 m) 2. Normand Mermaid Length = 90.1 m Beam = 20.5 m Draft laden = 7 m (maximum) Lift capacity = 50/100 t @ 22.5 m - Single & double fall
Cable installation vessel	Export cable installation	1. Van Oord Nexus (Source: https://www.vanoord.com)  2. Boskalis Ndurance (Source: https://boskalis.com)  3. DEME Living Stone (Source: https://www.deme-group.com) 	1. Van Oord Nexus Length = 122.68 m Beam = 27.53 m Draft laden = 5.83 m (design) Lift capacity = Main hoist 100 t / 15.00 m 2. Boskalis Ndurance Length = 99.00 m Beam = 30.00 m Draft laden = 4.8 m (design) Air draft = 7.00 m Lift capacity = 25 t at 25 m 3. DEME Living Stone Length = 161.00 m Beam = 32.2 m Draft laden = 11.5 m (Moulded) Lift capacity = 85 t (active heave compensated)

2.2.10 Draft offshore wind tender

In November 2022, MNRE released India's first-ever draft tender document for offshore wind. The draft is still under stakeholder consultation and the final tender is yet to be published. The key characteristics of a draft tender are as below:

- The first tender of 4 GW will be floated for offshore wind development in zone B off the coast of Tamil Nadu. It will consist of 4 blocks- each block with a capacity of around 1GW.
- As this tender is floated under model 3, no viability gap funding will be provided.
- A single-stage, two-envelope bidding procedure will be adopted, and bidding will be conducted through competitive bidding procedures.
- The first envelope will have 2 (two) parts, i.e., the preliminary qualification Bid (part I) and the techno-commercial bid (part II). The documents submitted by the Bidder towards meeting the preliminary qualification criteria (first envelope) will be scrutinized to establish preliminary qualification/ eligibility. This will be a pass/ fail test.
- On completion of the preliminary qualification Bid evaluation, the techno-commercial Bid of only those Bidders will be opened who are found to be qualified. The financial Bids, i.e., Quoted Lease Rental, in respect of each Block (second envelope) of only those Bidders who are found to be qualified and whose evaluated techno-commercial score is equal to or more than the minimum techno-commercial score.
- Weights shall be given to the evaluated techno-commercial score and financial Bids. The highest scoring Bidder (i.e., the composite of the evaluated techno-commercial score and financial score) will be declared the winning Bidder in respect of the Block and awarded the Project.
- The weights that will be given to the techno-commercial Bid and financial Bids are 70% (seventy percent), i.e., 0.7, and 30% (thirty percent), i.e., 0.3, respectively.
- The successful Bidder will have the exclusive rights over the allocated seabed to carry out the required study, survey and subsequent Project development in accordance with the Project Agreements.

Below is the sequential procedure for bidding and project agreement.

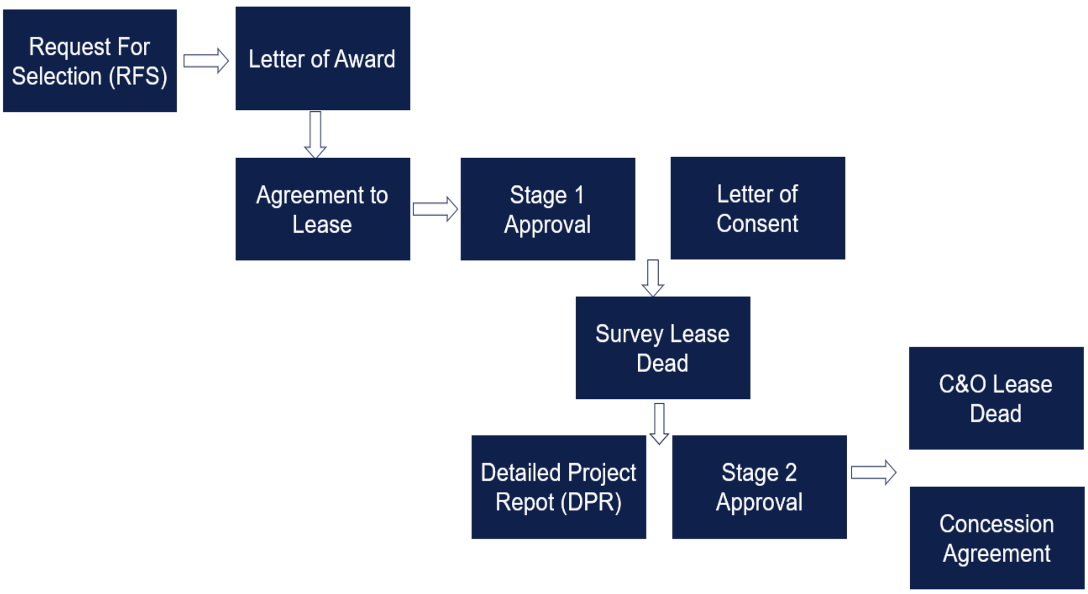


Figure 3-6 Bidding & project agreement in draft tender

2.2.10.1 Lease rate analysis

As stated earlier, the selection of bidders for offshore wind development is based on certain criteria. The quantum of lease rental accounts for 30% of the overall weightage, while the remaining 70% is allocated to the bidder's techno-commercial capabilities, encompassing offshore wind experience, commissioning, transmission system knowledge, operation and maintenance expertise, net worth, annual turnover, and more. This demonstrates that the government's primary objective is to choose an experienced and suitable bidder rather than solely focusing on generating revenue through leasing the seabed.

Prospective bidders will determine their lease rental based on their techno-commercial strengths, with a major emphasis on securing high scores in the techno-commercial evaluation. Additionally, the lease rental will impact the project's payback period and internal rate of return (IRR). Given these considerations, it is challenging to provide a general recommendation or specify an appropriate lease rental.

The following sections provide an overview of the global offshore wind market and highlight the lease rents discovered through auctions.

2.2.10.2 Global Offshore Wind Scenario

Different offshore wind markets have pursued varied strategies based on their priorities, local contexts, and preferences. When examining the major markets, the following observations can be made:

- Auctions are expected to dominate the procurement process in the future, comprising an estimated share of 97%.
- Auction designs exhibit a wide range of policy choices that are influenced by regional contexts.
- Ensuring revenue stabilization is a crucial aspect of procurement, particularly in emerging markets.
- Bid limitations of zero, observed in recent one-sided Contracts for Difference (CfD) auctions in Germany and two-sided CfD auctions in Denmark, have been identified as potential design flaws. These limitations have resulted in lotteries that are far from ideal from a policy perspective.

The table below presents a concise overview of the major offshore wind markets, highlighting their incentives, driving factors, limiting factors, and lease rates.

Country:	USA	UK
Incentives & driving/limiting factors	-Declining costs and federal policy for supporting the industry -New 30% investment tax credit was introduced for offshore wind projects that started construction before the year 2026. -National goal of achieving 30 GW of offshore wind power -The states like New York and New Jersey have set the goal of purchasing approx. 9 GW and 7.5 GW respectively by the year 2030 each -Hundreds of dollars are being invested by the two states for strengthening the port, manufacturing, and supply chain infrastructure and for making it conducive for offshore wind development -Clear competitive process for securing 30-year leases -Clear processes for permitting; Site Assessment Plan (SAP) and Construction and Operations Plan (COP) -Visible pipeline of offtake auctions for fixed bottom (REC/PPA). -No visibility on offtake for floating in Maine, Oregon or California. -O&G experience in the Gulf of Mexico. But no deep water states have offshore wind experience.	- National goal of 40GW of offshore wind capacity by 2030. -Developers take part in Contract for Difference (CfD) auctions to bid for support to build and run the wind farm -Separate lease and offtake auctions -Clear and established process driven by Crown Estate. - Clear consenting frameworks -Delays have been encountered due to avian and onshore grid impacts but proposals are underway to expedite planning. -15 year CfDs awarded via competitive Allocation Rounds. -Conditional investments into ports and manufacturing. -Fixed bottom experience in towers, blades, cables, foundation assembly & installation.
Lease Rate present? (Yes/No)	Yes	Yes. As per Round 4 Lease agreements; There are six R4 projects: Dogger Bank South West, Dogger Bank South East, Outer Dowsing, Morgan, Mona, and Morecambe. All have signed ten-year agreements for lease with the Crown Estate (TCE). Between them, they will pay TCE approximately £1 bn (€1.1 bn) per year as option payments. Option fees last at least three years, when they reduce and transition to rent payments if the project progresses to lease.
Lease Rate	up to USD 9,600/acre one time Fixed Amount.	approx. GBP 76,203 to 1,54,000/MW/annum.

Country:	Scotland	Norway
Incentives & driving/limiting factors	-Availability of Contract for Difference (CfD) -Alternative offtakes include PPA / hydrogen offtake - Clear consenting frameworks -Conditional investments into ports and manufacturing.	-Licencing processes described in the Ocean Energy Act. To date, projects have been licensed under the auspices of oil and gas. -Offtake model in development. Expected to be in the form of a competitive auction for a CfD. -Strong maritime expertise through oil and gas and offshore wind markets -Experienced in large structure manufacturing. -Has already fabricated, assembled and marshalled several floating wind projects, including TetraSpar and Hywind Tampen. -First Tender Launch Nearly Due
Lease Rate present? (Yes/No)	Yes	Yes
Lease Rate	approx. GBP 10,000 to 1,00,000/km2 one-time Fixed Amount.	The auction will be purely monetary i.e. lowest contract price wins.

Country:	Spain	Portugal	Italy
Incentives & driving/limiting factors	-Strong in the offshore wind on the back of onshore. -First mover advantage in manufacturing FOW -Capabilities across the value chain. Leader in chains and foundations; 4 concepts built in Spain to date. -Ports identified for aid of €1bn. -Strategic location of the Iberian peninsula.	-Developers going down the subsidy free route as no visibility on offtake regimes -Will be reliant on Spain -No O&G or fixed-bottom supply chain -No ports have been recognised for offshore wind development.	-New regulatory framework in development siting and permitting for offshore wind. Progress made, with enaction expected 2023/2024. -Limited deep water port capability across Sardinia, Sicily, and the mainland -Limited supply chain. Some strong players, e.g. Saipem, Prysmian, transferrable experience from O&G, and new entrants looking to gain footing, e.g. Vestas factory for V236 15.0 MW blades in Italy.
Lease Rate present? (Yes/No)	Yes	Yes	Not Available
Lease Rate	Not Available	Not Available	Not Available

Country:	France	South Korea	Japan
Incentives & driving/limiting factors	-Four pilots floating, and several fixed bottom farms have been awarded. -Mature site + subsidy ‘competitive dialogue’ tender process. -Three commercial floating sites are being tendered. -Despite regulatory amendments streamlining processes, legal challenges and opposition have caused lengthy delays. -Legislation in process to reduce planning and litigation windows -In France tenders are awarded on a site + offtake basis, providing a 20-year FiT/ CfD -Strong FOW engineering and production capacities, e.g. Eiffage Métal in Fos sur Mer is building PGL floaters. Converting Sète and Port la Nouvelle into FOW construction, logistics, and support hubs. Brest has an expanded 40ha quay and DAMEN Shipyards dry dock floater assembly. Marseille Fos includes a dock for floaters.	-Clear framework for early development exclusivity and grid allocation. -Range of permits needed from MOTIE, MOE and others. -Working towards a one-shop model to expedite and simplify permitting -Option of selling at market price to KEPCO with price topped by RE certificates. -CPPAs also possible -Strong transferable experience in shipbuilding; O&G; Steel. -Foundation manufacturers in the fixed bottom wind. -Local turbine manufacturers -Plans to expand and adapt multiple ports and industrial complexes for offshore wind -Strong international collaboration (e.g. at the Ulsan complex).	-Combined site + offtake auctions. -Maturing auction process; 1.7 GW awarded for fixed and 17 MW for floating. The 0.6 GW Kuji site is to be awarded in round 5/6 (mid-2020s) -More floating areas are needed. -No framework for EEZ -Approvals are required from multiple agencies (MOE, METI, MLIT) before and after the auction Japan is moving towards a ‘central’ system to speed up development -20 year FiT FiP secured with site lease during the auction -Green Innovation Fund for R&D -No framework yet for EEZ -Transferable experience from O&G, shipbuilding and maritime sector. Manufacturing and quality control excellence -Several floater manufacturers demonstrated small-scale projects in the past decade and in this decade -Targeting 60% local content.
Lease Rate present? (Yes/No)	Yes	Not Available	Yes
Lease Rate	Euros 44 to 120/MWh	Not Available	Japan is targeting cost reductions in offshore wind to reach the price of ¥8 to 9/kWh (€56 to 63/MWh) within 2030-2035 and localization of 60% by 2040.

Country:	Belgium	Denmark
Incentives & driving/limiting factors	-Under the current support scheme, domain concession holders receive renewable energy certificates from the Belgian federal energy regulator (CREG) for each MWh of offshore electricity production. Grid operator Elia is obliged to purchase the certificates under Electricity Law at a minimum price. -For 2023 onwards, the reference price is higher than the LCOE, and developers are projected to reap the rewards in 2023 2025 (table). Under the proposed two-way CfD scheme, profits will need to be paid back to the state, as opposed to operators receiving excess profits. -Older projects continue to operate under fixed support. These include C Power, Belwind, Northwind, and Nobelwind, securing a minimum price of €107/MWh for the first 216 MW of installed capacity and €90/MWh thereafter. These parks hold 20-year contracts and, according to energy regulator CREG, do not make any excess profits.	-Government-led auctions whereby the state defines the area and size of the potential wind farm and developers bid fixed kWh CfD offtake agreement. -The 'open door' scheme (now suspended), wherein the developer identifies an area and applies it to carry out preliminary investigations. -The Danish Climate, Energy and Supply Ministry has announced that there are plans underway to tender at least 9 GW of offshore wind energy projects within 2023.
Lease Rate present? (Yes/No)	Yes	Yes. The state defines the area and size of the potential wind farm and developers bid fixed kWh CfD offtake agreement.
Lease Rate	Older projects continue to operate under fixed support, securing a minimum price of €107/MWh (approx. USD 116/MWh) for the first 216 MW of installed capacity and €90/MWh (approx. USD 98/MWh) thereafter.	The Government is planning to initiate the bidding rounds for Energiø Bornholm and Hesselø in addition to another 5 GW of projects. The government is also exploring the possibility of

Country:	Germany
Incentives & driving/limiting factors	-First Tenders with Dynamic Bidding and Qualitative Criteria Launched -**Tender for Non-Examined Sites with Dynamic Bidding:** The first round, launched end of January 2023, includes 7 GW across three areas in the North Sea and one in the Baltic which have not been centrally pre-examined. Bids must be submitted by 1st June. -Developers bid for a market premium offtake with awards based on the lowest price in cents/KWh. The maximum bid price is set at 6.2 cents/kWh (€62/MWh) for auctions in 2023. Most recent auctions have been awarded without subsidy. -To bid, developers must provide signed declarations that at least 20% of the project capacity will be sold via PPAs with one or more companies for at least five years. The successful bidder has the right to apply for planning approval and is entitled to a grid connection. -**Dynamic Bidding for Multiple Zero Subsidy Bids:** Generally, the first bidding round is set at €30,000/MW. In the event only two bidders submit zero subsidy bids then the first bidding round is reduced to €15,000/MW. Bidders can progress to the

Country:	Germany
	next round, provided they match the bid level. -Bid levels will increase by €30,000/MW increments, providing all bidders submitted bids at the specified bid level. Otherwise, the incremental increase is reduced to €15,000/MW. -**Pre-examined Tenders with qualitative criteria:** The Federal Network Agency launched a further 1.8 GW worth of tenders for offshore wind energy on 27th February for pre-examined sites. The bid deadline is 1st August, with results four months later. Developers must submit a financial bid value in euros and a project description, which must contain information on four other qualitative criteria. If multiple bids receive the same number of points, the highest financial bid wins. If multiple bidders submit the same price, they will be invited to raise it. -**Milestones and Risks:** A security deposit is determined from the bid amount multiplied by €100/kW for non-examined sites and €200/kW for pre-examined sites. 25% of the security deposit is due by the bid deadline. The remaining 75% is due within three months of the award. The difference in deposit between examined and non-examined tenders likely reflects the increased risk for the latter due to fewer site data available prior to tender and additional expense to the developer to conduct site investigations.
Lease Rate present? (Yes/No)	Yes
Lease Rate	Multiple schemes and specific rates & terms as mentioned above.

Country:	Estonia	China	Taiwan
Incentives & driving/limiting factors	-Last year, the Estonian maritime spatial plan was completed and some areas were dedicated to offshore wind development. These areas will be divided into three to four parts and put up for auction in September. Winners of the auction will play a key role in Estonia's energy future.	The first auction under the new regulation launched in June 2019 was for the Fengxian offshore wind project (200 MW) in Shanghai.	Five developers bid into Taiwan's first auction: (1) Northland Power & YuShan Energy, (2) Swancor & Macquarie, (3) Ørsted, (4) Copenhagen Infrastructure Fund, and (5) Taipower. Two sponsors, Northland Power & YuShan Energy and Ørsted, and four wind farms were selected, with a bidding price ranging from NT$2224.5/MWh (€65/MWh) to NT $2548.1/MWh (€75/MWh) and the average winning bid at NT$2386/MWh (around €63/MWh), marking an almost 60% reduction from the FIT awarded in 2018.
Lease Rate present? (Yes/No)	Yes	Yes	Yes
Lease Rate	The auction's starting bidding price is €15,000/km2.	Up to €93.42/MWh	Up to €75/MWh

3 OFFSHORE WIND-TO-HYDROGEN

3.1 Introduction to the offshore wind for hydrogen production

There is an increasing interest in offshore hydrogen production, fed by energy generated by offshore wind farms. DNV sees customers who want to quantify the effects of design choices in wind-to-hydrogen value chains. These design choices should freely – yet thoroughly – be explored and adapted to reach the optimal solution for each unique offshore project. DNV aims to provide trust and early project risk mitigation in this space. This section will introduce common topologies in wind-to-hydrogen value chains.

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

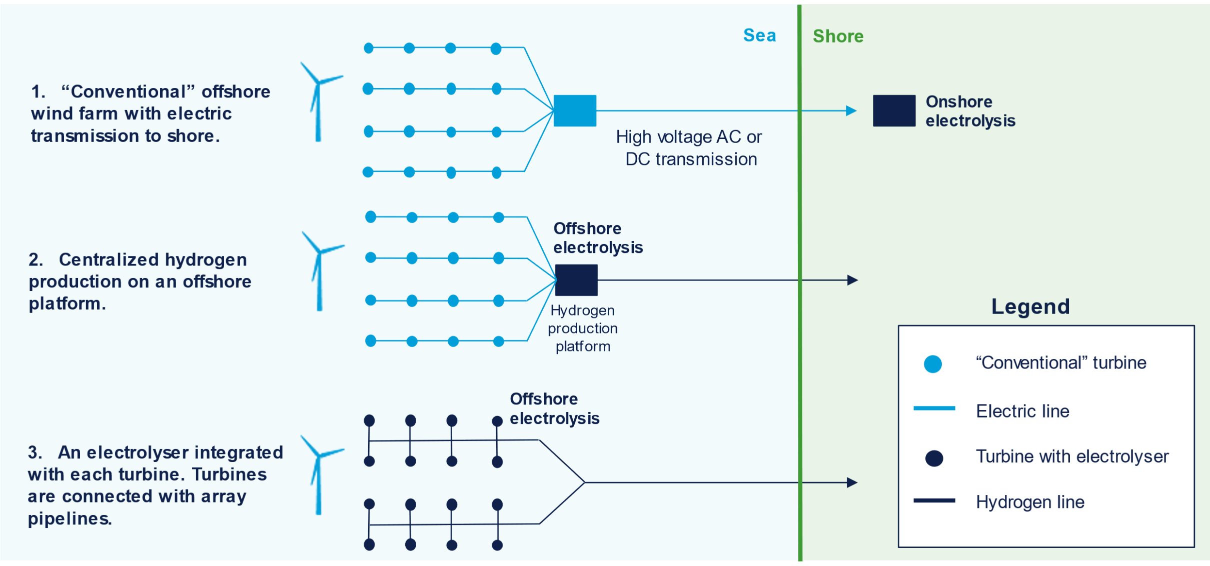


Figure 4-1 - Offshore hydrogen production concepts

4. **The first configuration** features a conventional wind farm, but instead of connecting to a grid, it is directly connected to an electrolyser plant which is located onshore.
5. **The second configuration** still resembles a conventional offshore wind farm but will be not connected to the grid. Instead, the electrolyser plant is part of the infrastructure to transport energy to shore. The electrolyser plant is located on a centralized platform (comparable to a substation) and is receiving electricity from the array cables, which are used to produce hydrogen from seawater. Hydrogen is transported to the shore using a hydrogen export pipeline.
6. **The third configuration** integrates the hydrogen production at the turbine. A smaller electrolyser unit is directly connected to the turbine to generate hydrogen and will omit the requirement for array cables. Instead, array pipelines are used, which transport the hydrogen to a central point, where it will be fed into the hydrogen export pipeline and transported to shore.

Dedicated or hybrid energy transport

The three configurations can be dedicated, where all electricity is converted to hydrogen, but alternatively, a hybrid system can be chosen. A hybrid system still has both a connection to the grid as well as a connection to the electrolyser. Both connections, electric and hydrogen, can be at full capacity or a smaller part of the capacity. E.g. for a 15 MW hybrid turbine, 10 MW can be converted to hydrogen with a 10 MW electrolyser and the remaining 5 MW can be connected electrically. The connecting infrastructure, array pipes and cables and further export pipes and cables should be designed to the required capacity as well. Such a system allows the operator to choose between different markets (hydrogen or electricity). A downside of a hybrid configuration is the dual cost of electrical and gas transport infrastructure. For the sake of comparison, this report only describes dedicated value chains. E.g. in the case of offshore hydrogen production, only hydrogen transport infrastructure from the point of production to the coast is included. The three topologies are discussed in more detail below.

3.1.1 Conventional concept – hydrogen production at a centralized onshore plant

A schematic representation of the Onshore Centralized topology is given in Figure 4-3.

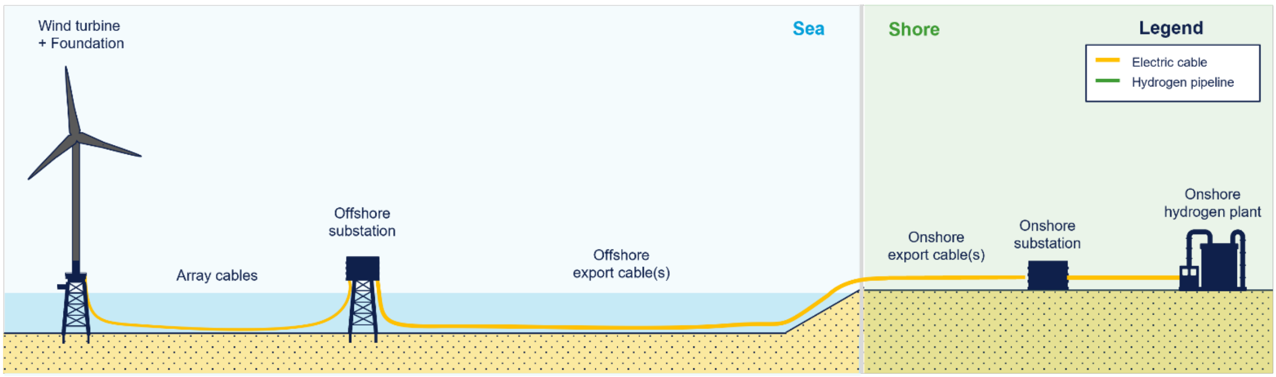


Figure 4-2: Schematic representation of the Onshore Centralized topology

This concept features the lowest amount of adaptations to a conventional electrically connected wind farm. At the onshore substation (a part of) the available energy gets transmitted to the hydrogen plant. There, depending on the voltage level of the transport, the power will be stepped down to medium voltage (10 – 40 kV_{AC}) through a transformer system. It is usually assumed for large-scale plants that the water supply will be covered by the desalination of seawater. A detailed schematic of this topology is available in section B.1.

Figure 4-3 - 1,000 MW Hydrogen production plant concept [ISPT]

The current state of the technology & development expectation

A large majority of wind-to-hydrogen projects around the world feature this topology. This makes sense given that all individual components of the system feature a high TRL (7 – 9). However, a complete system has not yet been built, certified or operated. A lot of development and learnings from first-movers will drive innovation in the coming decade, potentially enabling this technology on a commercial scale from 2025 onward.

Main developments:

- Existing wind farms connected to new-built hydrogen production plants

- Overarching control system for the wind farm and hydrogen plant
- Island mode operation of the wind farm (black start)
- Standards, certification and legislation to enable this concept
- Current TRL: 6/7
- The first system deployed at relevant scale (Year): 2025
- Upscaling of supply chain and experience in the electrolyser industry

3.1.2 Centralized platform concept – hydrogen production on an offshore platform

A schematic representation of the Offshore Centralized topology is given in Figure 4-4.

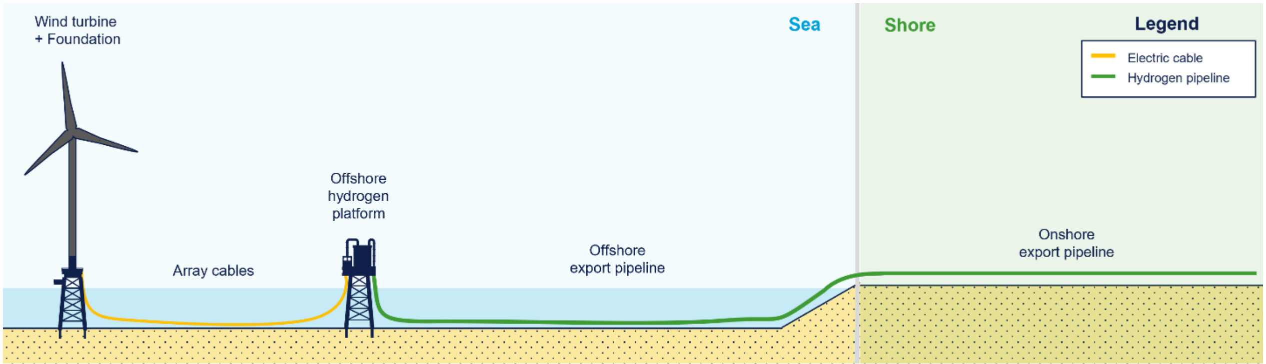


Figure 4-4: Schematic representation of the Offshore Centralized topology

The platform concept assumes hydrogen production on an offshore platform to which multiple turbines are connected through array cables. The voltage received at the platform is 33 – 132 kV_{AC} (mostly 66 kV_{AC}) where it is transformed to medium voltage (10 – 40 kV_{AC}) through a transformer system. Other equipment on the platform includes the electrolyser, the water treatment and the cooling. This concept also uses seawater for cooling and desalination and water treatment to provide clean water. All equipment is placed on multiple decks. The maximum expected capacity of a hydrogen production platform (in terms of installed electrolyser plant size) is around 500 – 800 MW. A detailed schematic of this topology is available in section B.1.

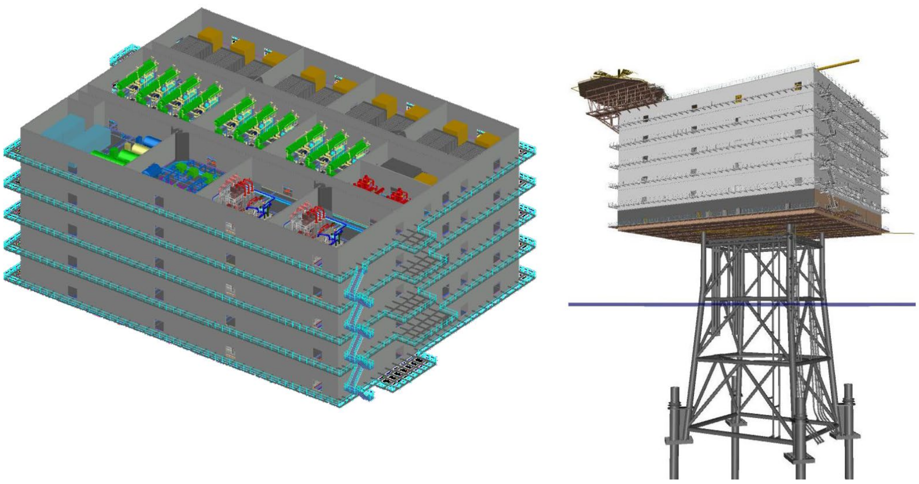


Figure 4-5 - 500 MW Hydrogen production platform concept [Fraunhofer ISE]

Water electrolysis may be carried out on offshore platforms, either through refurbishing existing Oil & Gas platforms or building new greenfield platforms. The platforms may be bottom-fixed or floating. Electricity is sourced from an offshore wind farm which is typically isolated from the main continental grid. Hydrogen generated at the platform is compressed and transported in a hydrogen pipeline to shore. The platform contains all necessary auxiliary systems for stand-alone hydrogen production, including step-down and conversion of wind farm AC to DC power, seawater desalination, hydrogen compression, cooling of electrolysers and power equipment, backup power, communications and control and other ancillary systems. Offshore electrolysis typically utilizes seawater that is desalinated on-site.

The current state of the technology & development expectation

Of the offshore hydrogen production concepts fixed platforms are considered the most mature. Several pilot projects are currently underway, as is further explored in section 4.5. The most advanced is the PosHYdon project in the Netherlands, which will test a 1.25 MW electrolyser from NEL on an existing unmanned natural gas platform operated by Neptune Energy 13 km from the coast and a water depth of about 40 m. Other projects that are considering the use of platforms (fixed or floating) include the AquaVentus project in Germany, Deep Purple™ in Norway and SEM-REV in France. Floating platforms for hydrogen production are less mature due to the lack of experience with floating electrolysis and the subsequent need for flexible pipelines that connect the platform to the export pipeline.

The main challenges across all forms of offshore hydrogen production concepts are the island mode operation of wind turbines and the adaptation of electrolyzer products to work in unmanned, offshore environments. E.g. if there is a major fault and maintenance is required, it could take a long time for the maintenance engineers to reach the electrolyzer plant and perform repairs, resulting in a large loss of production. The current onshore designs have to be adapted to minimize the maintenance requirement. Currently, there is very little experience in the industry with electrolyzer maintenance in general. First experience with onshore maintenance has to be gained before offshore maintenance will become feasible.

- Overarching control system for the wind farm and hydrogen plant
- Current TRL: 5-6 (fixed platform)
- The first system deployed at relevant scale (Year): 2030
- Limitations in offshore hydrogen production: Requires wind farms to operate in island mode, which is not possible by default.
- Back-up power to support auxiliary and safety systems of the complete platform and wind farm.

3.1.3 Integrated concept – hydrogen production at the offshore turbine

A schematic representation of the Offshore Decentralized topology is given in Figure 4-6.

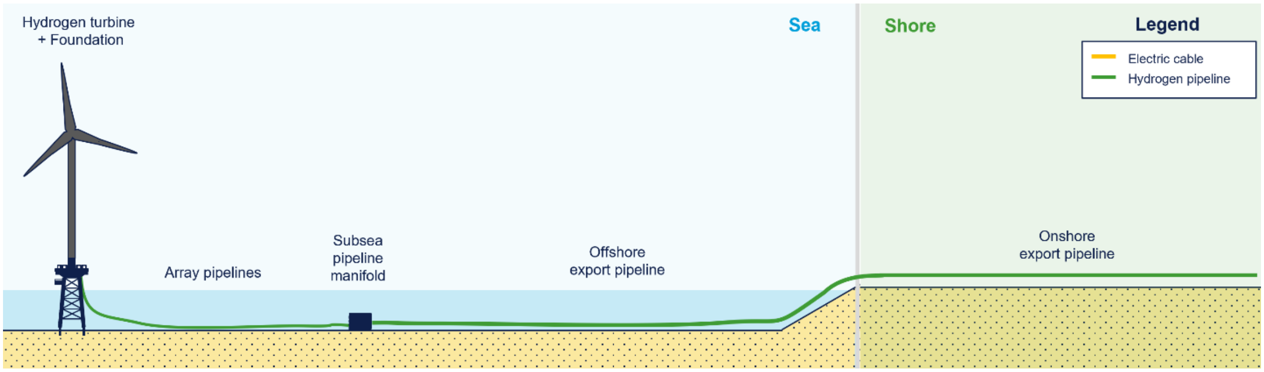


Figure 4-6: Schematic representation of the Offshore Decentralized topology

The integrated concept assumes hydrogen production at the turbine where an electrolyser is located at the base of the turbine. The additional support structure is required to extend the working platform of the turbine for the hydrogen production equipment to be placed in containers. The hydrogen production facility is integrated into a single (floating) wind turbine, operating in island mode. This omits the need (and cost) for electrical interconnection with other turbines/facilities, as well as the need for generating 50 or 60 Hz AC. The generated hydrogen is transported via array pipelines, either directly or via a centralized hub on a platform. The system consists of (floating) wind turbine, power conversion electronics, seawater desalination system, electrolysis plant (stacks, gas purification, cooling system, control system) and hydrogen compression. This concept features many degrees of freedom for cost optimization and is currently being developed by several wind turbine OEMs, such as Siemens Gamesa (see Figure 4-7).

Figure 4-7 - Turbine-integrated hydrogen production platform concept [Siemens Gamesa]

As can be seen in **Figure 4-8**, this equipment includes the electrolyser, water treatment and cooling and receives medium voltage (10 – 40 kV_{AC}) from the turbine. Seawater is used for both cooling and desalination and is treated to supply clean water to the electrolyser. To further transport the produced hydrogen, a connection will be made to array pipelines which collect hydrogen from each turbine and further transport it to a manifold or central compressor. A detailed schematic of this topology is available in the section B.1.

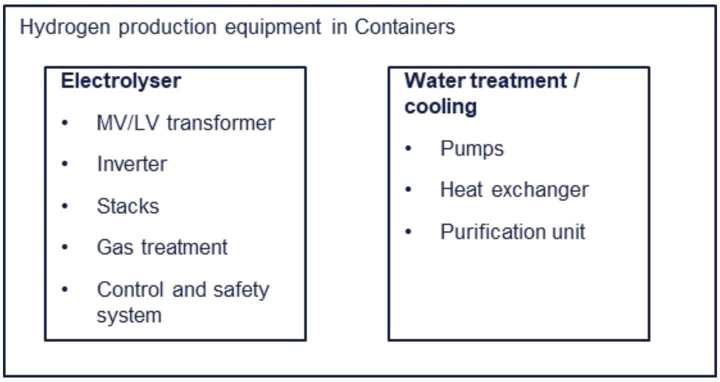


Figure 4-8: Schematic representation of containerized hydrogen production plant

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

Other optimizations can also be found in the design of the turbine. The design of a turbine, the generator size and the rotor diameters assume certain economic considerations and optimizations. The optimum for a "conventional electric turbine" could differ from the optimum design for a hydrogen turbine. By changing the rotor diameter or generator, the utilization or maximum yield can be influenced. With the additional costs for hydrogen production equipment, a different optimum design can be found. Optimizations such as those described above could reduce the hydrogen production costs from offshore wind but are still to be further developed and evaluated by industry. Section 4.4 further elaborates on this topic.

The current state of the technology & development expectation

All individual components of the system feature a high TRL (7 – 9). However, the complete system has not yet been built, certified or operated. A lot of development and learnings from first-movers will drive innovation in the coming decade, potentially enabling this technology on a commercial scale from 2035 onward.

Main developments:

- Larger specific power/generator, optimized wind-farm layouts
- Island mode operation of the turbine (backup power)
- Compact and efficient electrolyser designs & (solid-state) power electronics.
- Remote electrolyser operation & managing maintenance cost
- Certification and legislation to enable this concept
- Adaptations/optimization to standardized turbine design
- Current TRL: 3
- The first system deployed at relevant scale (Year): 2030
- Limitations in offshore hydrogen production: Current developments are mostly focused on bottom-fixed structures. The implications for floating wind turbines, regarding metocean conditions and their impact on the hydrogen production equipment and auxiliaries, are not yet fully explored.

3.2 Components in wind-to-hydrogen value chains

A simplified overview of components that make up the three value chains described in the previous section is given in Table 4-1 below.

Table 4-1 - High-level overview of components in three wind-to-hydrogen value chains

Component / Topology	1. Onshore electrolyser	2. Offshore hydrogen production platform	3. Turbine-integrated hydrogen production
Foundation + Wind turbine	✓	✓	✓
Turbine add-on structure for hydrogen production	✗	✗	✓
Array Cables	✓	✓	✗
Array Pipelines	✗	✗	✓
Offshore substation	✓	✗	✗
Offshore hydrogen production platform	✗	✓	✗
Export cable(s)	✓	✗	✗
Export pipeline(s)	✗	✓	✓
Onshore substation	✓	✗	✗
Onshore hydrogen production plant	✓	✗	✗

✓ = Component present in the value chain
✗ = Component not present in the value chain

To identify and assess the technical feasibility of the selected concepts we have produced a high-level design and have evaluated each component individually as well as the whole system. The assessment includes current technology readiness levels (TRL's), main barriers, ongoing developments, and an expectation of the TRL after 2030.

3.2.1 Offshore turbines

Offshore turbines are a proven technology and current developments focus on increasing the size of the turbines. Turbines in the range of 14-18 MW are currently being developed and will likely be the standard until after 2030. After 2030, towards 2035, 20 MW turbines are a likely option. Although offshore floating wind is less developed it is expected that the same turbines will be applied. The difference will be in the substructure which can be fixed or floating. The standardized turbine designs can be applied to both types. Section 5 further elaborates on this.

3.2.2 Substructures

Structures for wind turbines

Offshore wind foundations are complex structures that are designed to resist different types of loads such as:

- High dynamic wind turbine loads result in significant fatigue loads within members and joints;
- Cyclic soil loading and large lateral load transfer through pile-soil interaction (significant overturning moments);
- Hydrodynamic loading from waves and currents;
- Extreme typhoon loads; and
- Earthquake loading in some regions with potential for soil liquefaction.

In addition to this complex loading, the "design problem" is compounded with increased loads as offshore wind turbines continue to grow in power. Offshore turbine capacities have grown at an annualised 16% rate since 2015. The current market trend shows turbines being installed of 8 MW to 10 MW size with turbines moving towards the next generation in size ranging from 10 MW to 15 MW for future projects. It is expected that further in the future (for projects entering operation in 2026 to 2030), the industry will be looking towards offshore turbines of 20MW+ rated capacity.

Also, the water depth of offshore wind farms installed is increasing, as the wind farms are moving further away from shore in order to utilise better offshore wind resources. Each type of offshore foundation has its own limitations in design and hence can be used optimally for specific conditions. Fixed-type foundations are being used up to a water depth of approximately 60m while emerging floating foundations are for use in water of up to perhaps 500m.

3.2.2.1 Foundation design types

Offshore wind foundation designs can be broadly classified as fixed-type foundations and floating-type foundations.

Fixed type foundations:

Different fixed-type foundation options considered and prevalent in the wind turbine offshore market include:

- Monopiles
- XL Monopiles
- Gravity base Structures
- Jackets (piled)
- Tripods
- Triples
- Suction caisson (monobucket)
- Suction caisson (jackets)

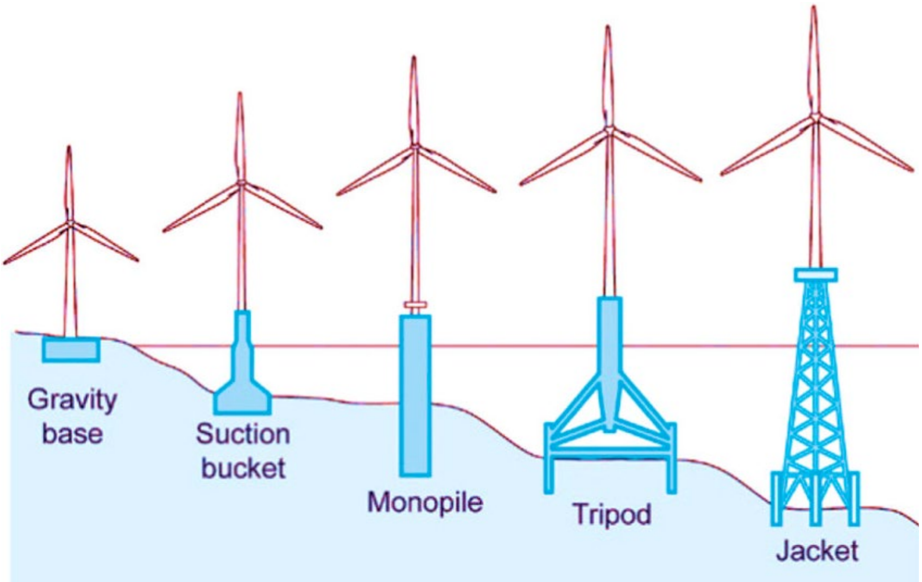


Figure 4-9 Bottom Fixed offshore wind foundation types [2]

Floating type foundations:

Numerous floating foundation concepts are in development, and some technology convergence is expected. Floating wind foundations can be broadly categorized into the following types:

- Barge,
- Semi-submersible platform,
- Spar,
- Tension-Leg Platform.

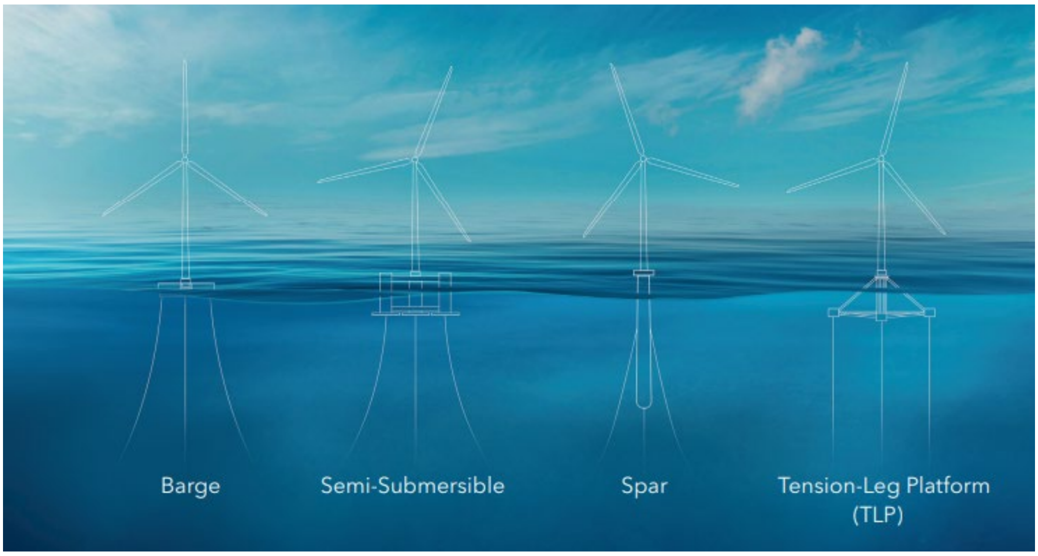


Figure 4-10 Floating Foundation Types

Floating foundations have typical advantages as they allow access to deep-water sites, enabling wind farms to be developed that are not possible with bottom-fixed foundations (such as in the US, Japan). Floating wind is attracting increasing investment and public policy support because it can access the estimated 81% of total offshore wind electricity generation potential that is in waters deeper than 40 meters. There, the wind is more consistent, but using bottom-fixed offshore wind support structures may be less feasible technically, logistically, and economically, or just impossible. Another advantage of floating wind is to avoid construction at sea altogether – an activity that is both inherently risky and expensive. Floaters can be built onshore; the turbine can be erected in the port and the structure can then simply be towed to its location, an activity requiring much simpler vessels (tugboats) than the offshore installation of fixed-bottom turbines and much less sensitive to weather conditions.

Table 4-2 Difference between Bottom fixed and floating foundations

	Bottom Fixed	Floating
Definition	Rigid structure firmly anchored to the seabed	The platform that floats on the water's surface
Deployment	Suitable for shallow to intermediate water depths	Suitable for deep water and transitional zones
Foundation Types	Monopile, jacket, gravity-based structures, etc.	Semi-submersible, spar, tension leg platform, etc.
Stability	Relies on seabed friction for stability	Uses mooring lines and ballast systems for stability
Water Depth Range	Typically, up to 70 meters	Typically, deeper than 70 meters
Installation	Less complex installation process	More complex installation process
Cost	Generally lower cost due to simpler design	Generally higher cost due to advanced technology
Maintenance	Reactive in Nature, easier access to maintenance and repairs	Proactive in Nature, more challenging access and maintenance
Scalability	Limited to shallow water areas and smaller turbines	Enables larger turbines and expands potential areas
Environmental Impact	Potential impact on marine ecosystems and fisheries	There are potentially different impacts and these are far less established than fixed foundation turbines given their relative newness.
Development Experience	More mature technology with a longer track record	Emerging technology with ongoing development
Grid Connection	Typically connected via subsea cables	Typically connected via subsea cables

3.2.2.2 Project Reference for fixed and floating foundations

This section gives some reference projects with floating and bottom-fixed foundation types. The technology for floating wind foundations is rapidly maturing. There are a number of different floating foundation concepts that are being developed, and the technology is becoming increasingly cost-competitive. DNV has only covered spar and semi-submersible type floating foundation types as these technologies have an installation track record for commercial projects.

<table>
<tr><th>Project</th><th>Foundation Technology</th></tr>
<tr><td>Hywind Tampen</td><td>Floating (Spar)</td></tr>
<tr><th>Project Description</th><td rowspan="2">
Figure 4-11: Hywind Tampen [3]</td></tr>
<tr><td>The Hywind Tampen wind farm is a floating offshore wind farm located in the Norwegian North Sea. It is the world's first floating wind farm to power offshore oil and gas platforms. The wind farm consists of 11 wind turbines with a total capacity of 88 megawatts (MW). The wind turbines are installed on a floating concrete structure with a joint mooring system.

The Hywind Tampen wind farm is a joint venture between Equinor, Petoro, OMV, Vår Energi, Wintershall Dea and INPEX Idemitsu Norge. The wind farm is expected to generate enough electricity to power the Snorre and Gullfaks oil and gas platforms, reducing CO2 emissions by more than 200,000 tonnes per year.</td></tr>
<tr><th colspan="2">Project Details</th></tr>
<tr><td colspan="2">
• Wind Foundation: Floating (Spar)
• Wind Turbine Model: 8 MW (Siemens Gamesa)
• Total capacity: 88MW
• Country: Norway
• Status: Operational (2022)
• Material: Concrete
• Diameter: 14.7 m
• Height: 91 m
• Draft:78 m
• Mooring System: Taut
• Water depth: 260-300 m
</td></tr>
</table>

<table>
<tr><th>Project</th><th>Foundation Technology</th></tr>
<tr><td>Windfloat</td><td>Floating (Semi-Submersible)</td></tr>
<tr><th>Pilot Description</th><td rowspan="2">
Figure 4-12: Wind float [4]</td></tr>
<tr><td>The WindFloat Atlantic wind farm is a floating offshore wind farm located in the Portuguese Atlantic Ocean. It is the world's first commercial-scale floating wind farm. The wind farm consists of 3 Vestas V164 wind turbines 8.4 MW) with a total capacity of 25 megawatts (MW). The wind turbines are installed on a floating semi-submersible platform.</td></tr>
<tr><th colspan="2">Project Details</th></tr>
<tr><td colspan="2">
Wind Foundation: Floating (Semi-Submersible)
Wind Turbine: 8.4 MW (Vestas)
Capacity: 25 MW
Country: Portugal
Status: Operational (2020)
Material: Steel
Length:75 m
Width: 75 m
Height: 30 m
Draft: 20 m
Mooring System: Catenary
Water Depth:100 m
</td></tr>
</table>

<table>
<tr><th>Project</th><th>Foundation Technology</th></tr>
<tr><td>Hai long</td><td>Bottom Fixed (Jacket)</td></tr>
<tr><th>Pilot Description</th><td rowspan="2">
Figure 4-13: Hai long [5] [6]</td></tr>
<tr><td>The Hai Long 2A offshore wind farm is a 300 MW offshore wind farm located in the Taiwan Strait. It is being developed by a consortium of Northland Power, Yushan Energy, and Mitsui & Co. The wind farm is expected to be operational in 2024.

The Hai Long 2A segment of the project will employ Siemens Gamesa’s new SG 14-222 DD 14MW</td></tr>
<tr><th colspan="2">Project Details</th></tr>
<tr><td colspan="2">

- Wind foundation: Bottom Fixed (Jacket)
- Wind Turbine: 14 MW (Siemens Gamesa)
- Capacity: 300MW
- Country: Taiwan
- Status: Under Constraution
- Material: Steel
- Height: 94 m
- Weight:2000 ton
- Water Depth: 30-50 m

</td></tr>
</table>

<table>
<tr><th>Project</th><th>Foundation Technology</th></tr>
<tr><td>Moray West</td><td>Bottom Fixed (Monopile)</td></tr>
<tr><th>Pilot Description</th><td rowspan="2">
Figure 4-14: Moray West [7]</td></tr>
<tr><td>The Moray West offshore wind farm is located in the Moray Firth, Scotland. The wind farm has a capacity of 882 MW. The wind farm will feature 60 of Siemens Gamesa's SG 14-222 DD offshore wind turbines. Each turbine will have a rotor diameter of 222m, swept area of 39,000m^2 (419,792.5ft^2) and three 108m-long blades and will be able to produce 14.7MW of electricity.</td></tr>
<tr><th colspan="2">Project Details</th></tr>
<tr><td colspan="2">

Wind foundation: Bottom Fixed (Monopile)
Wind Turbine: 14.7 MW (Siemens Gamesa)
Capacity: 882 MW
Country: Scotland
Status: Under Constrution
Material: Steel
Length: 90 m
Diameter:10 m
Weight:2000 ton
Water Depth: 22-57 m

</td></tr>
</table>

Structures for electrical and hydrogen production equipment

In general, both fixed and floating substructures have been widely applied for in the oil and gas industry. Although for turbines different loads and scales apply, for electrical and hydrogen production equipment it is expected that a similar approach can be taken. DNV does not expect significant challenges with the substructure for facilitating both the electrical equipment and the hydrogen production equipment. Section B.3 further elaborates on this.

There are however expected challenges with dynamic behaviour and the electric cables and pipes that connect to the platform ("dynamic risers") when floating structures are applied. Rising cables and pipes need to be suitable for dynamic application due to stresses from the moving platform. These dynamic cables and pipes are already applied but DNV still recommends fixed structures for the hydrogen production platform and electric substations for the near future. Fixed structures are still feasible for water depths of 90 – 120 m and these will need to carry heavy topsides (5 – 15 kt) with the estimated costs for both fixed and floating in the same range.

In addition, risers for hydrogen still need to undergo more research and development. Risers applied in the Oil and Gas industry use steel armour to provide tensile strength. Permeating of hydrogen will likely affect this armour and reduce tensile strength. It is unclear if these risers will be applicable to hydrogen. Composite pipes are an alternative. These are fully bonded systems that use carbon or aramid fibre to provide tensile strength. This material is not affected by hydrogen and is therefore likely applicable. The development and supply chain of these pipes is however still limited but can be scaled up during the coming decade.

3.2.3 Electric connection

The concept of onshore hydrogen production requires an electric connection between the offshore wind farm and the onshore hydrogen production plant. Long distances become challenging with HVAC. Although still possible, reactive power needs to be compensated by either a connection to the grid with full capacity or with reactive power compensation between the wind farm and the onshore hydrogen production plant. An HVDC connection is a more feasible alternative in cases of long distances and large capacities. Both HVAC and HVDC offshore power transmissions are technically mature and are expected to further commercially mature towards 2030 and afterwards. For both technologies, the turbine and array cable voltage (typically 33kV or 66 kV, 132 kV in development) are stepped up to a higher voltage for transport.

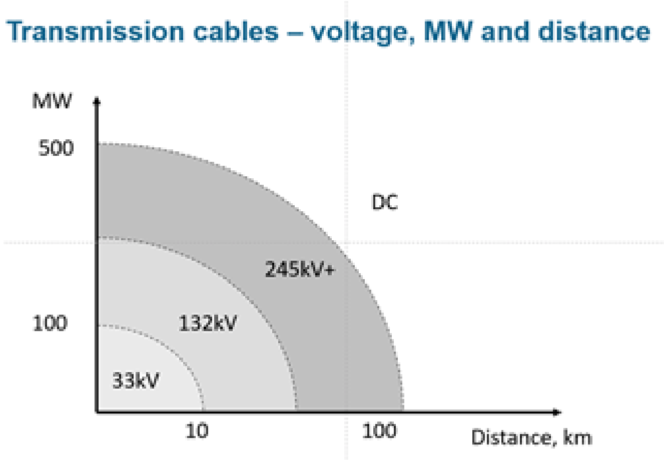


Figure 4-15 - Schematic representation of design choices for offshore power transmission

In HVAC concepts transmission losses rise with the voltage, the capacitance, and the cable length. Beyond the so-called critical length (100 to 150 km depending on cable type) there will be no capacity left for active power transmission. The best way to increase transmission capacity is to increase the voltage level, but because reactive power increases with the square of the voltage the voltage increase reduces the critical length and disqualifies higher capacity AC for longer distances.

In HVDC transmission losses increase with the cable length but are not affected by capacitance. As a result, HVDC is the technology of choice for distances higher than 100 – 150 km. Additionally, DC converter costs are higher than AC converter costs, but cable costs are lower than AC transmission.

In the offshore production topologies, no high-voltage transmission is present. Rather, in the offshore centralized topology the array cables from the wind farm directly transmit the power to the hydrogen production platform at the same voltage as the turbines. In the offshore decentralized topology, the power generated by the turbine is directly fed to the hydrogen production equipment co-located with the turbine.

Section 5.4 further elaborates on this topic.

Transformers for offshore hydrogen production

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

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

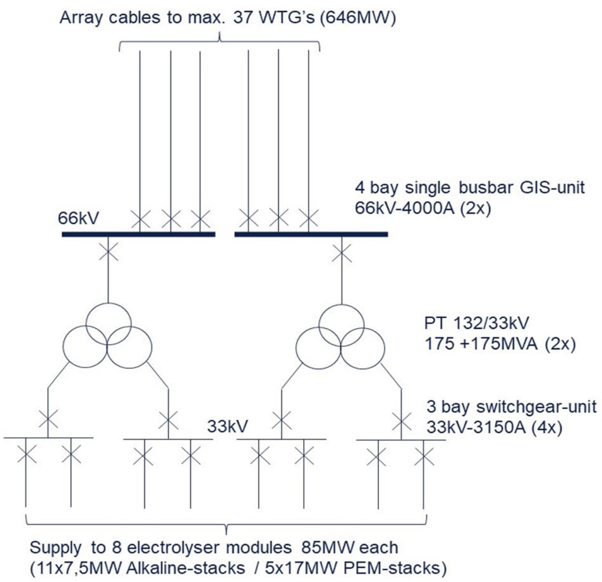


Figure 4-16 Supply station 66/33kV – 646MW (at platform)

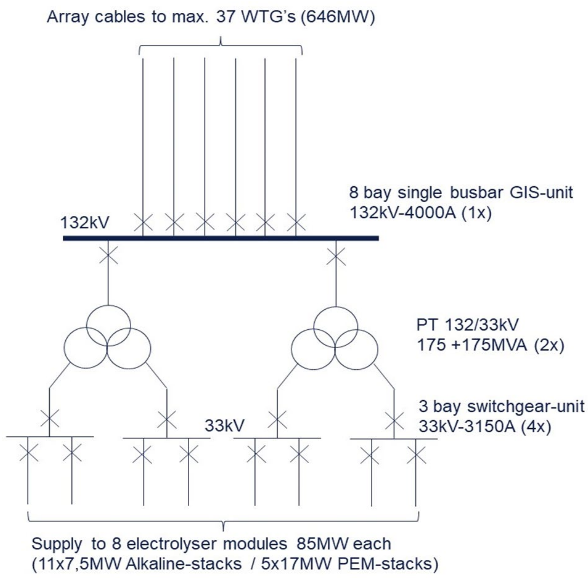


Figure 4-17 Supply station 132/33kV – 646MW (at platform)

The cost difference between both configurations is considered minimal and a simplified cost of 33,100 €/MW is derived for the configurations described above. This is excluding installation on the platform topside which should add roughly 20 – 30%. The costs are considered to scale linearly with capacity and no big cost reductions are expected from technology development.

3.2.4 Electrolyser

Although electrolysers have been operating for multiple decades already, the energy transition has provided a boost for further development and upscaling. The main developments are related to upscaling of both systems and supply chain, improvement of performance, cost reduction and application/integration with renewable energy. Electrolysers are currently in the scale of only multiple MW and manufacturers are getting ready to apply modular systems that allow for the scale-up of complete plants in the range of hundreds of MW to GW. GW scale plants are expected to be technically feasible towards 2030 but a successful development of the current global project pipeline (consisting of hundreds of MW plants) is key.

While the scale is one important aspect of technical feasibility, the offshore application is another aspect. The current focus is on electrolyser development for onshore applications, although some development is also working towards offshore applications. The offshore application requires compact systems and operation and maintenance based on limited interventions. In general, the development for both onshore and offshore applications is heading in the right direction, but for offshore development, this adds additional challenges and development. Offshore application of electrolysis can be technically feasible by 2030 but development and pilot projects should start soon.

When focussing on the different technologies we mainly consider pressurized alkaline and PEM suitable for offshore application as these systems are compact and can respond to variable energy input from wind. Atmospheric alkaline has a larger footprint and is less capable of responding to variable energy input. However, this technology could be an option for the onshore concept in combination with pressurized alkaline or PEM. This should be considered during concept optimization.

Both Solid Oxide (SOEC) and Anion Exchange Membrane (AEM) are not expected to be feasible for offshore hydrogen production. Solid Oxide requires an external source of heat which is not available offshore and it is uncertain if this will be available onshore, although integration with downstream processes (such as ammonia or methanol production from hydrogen) may in future provide some synergies. However, Solid Oxide is not ideal when combined with intermittent renewable energy. Although Anion Exchange is expected to eventually become technically suitable, we do not expect this technology to be sufficiently developed within the envisaged timeframe of the project.

Additional discussions and data on electrolysers can be found in section B.1 in APPENDIX B:

3.2.5 Water treatment

Water treatment is mature and multiple technologies are available. In our assessment, we assume thermal desalination to extract clean water from the sea. Additional cleaning steps are included in the electrolyser plant as this is usually part of the electrolyser manufacturer's delivery scope.

Thermal desalination

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

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

Additional treatment should be added to further clean the water and get it to the required purity. For electrolysers, this is typically indicated as a water conductivity requirement and is in the range of <5 µS/cm for alkaline and <1 µS/cm for PEM. The volume of clean water required to produce 1 Nm^3 of hydrogen is approximately 1 litre which roughly equates to 0.3 m^3/h of clean water per MW of electrolyser. To produce 1 m^3 of clean water the process uses approximately 6 kWh of electric energy to power pumps etc. and 750 kWh of thermal energy which is roughly 60% of the available heat from the electrolysis process (assuming $75\%_{HHV}$ electrolyser efficiency).

Based on conversations with a thermal desalination supplier, the technology is mature and has already been applied offshore. Other technologies such as reverse osmosis (RO) could also be considered and are also mature, but we have not performed a detailed assessment here.

Wastewater

An electrolyser facility will probably have to deal with 7 possible sources of wastewater:

1. The concentrates of the RO reject stream
2. Rejects from the chilled water system (if any)
3. Condensates from the hydrogen cooling/drying (if not recycled)
4. If evaporation cool water is used there is a drain that needs to be assessed
5. Rainfall water that might be contaminated with chemicals (especially alkaline)
6. Water for firefighting
7. Wastewater from desalination if seawater is used (maybe)

The outcome of all this is that you have to deal with waste water with higher concentrations of chemicals that are already present (in lower concentrations) in the water source that is used. What you need to do very much depends on local requirements and options (you may simply dilute the water with (sufficient) amounts of the original water source but that is not accepted everywhere.

Brine disposal best practice in India

The Central Pollution Control Board (CPCB) of India has issued guidelines for the disposal of brine into the sea. These guidelines are intended to protect the marine environment from the harmful effects of brine discharge. The guidelines state that brine discharge should be carried out in a manner that minimizes the impact on the marine environment. This includes the following:

- The brine should be discharged at a distance of at least 500 meters from the shore.
- The brine should be discharged at a depth of at least 10 meters.
- The brine should be discharged in a manner that minimizes the formation of plumes.
- The brine should be monitored to ensure that it does not exceed the permissible limits for contaminants.

The CPCB has also issued guidelines for the treatment of brine before it is discharged into the sea. These guidelines are intended to remove harmful contaminants from the brine and make it less harmful to the marine environment.

3.2.6 Compression

Due to hydrogen's low density reciprocating compressors are used to compress hydrogen. These compressors have already been applied for hydrogen, on a large scale. Reciprocating compressors for offshore applications are already mature and solutions include both offshore compressors on fixed or floating platforms, and sub-sea. Although offshore compressors have not yet been applied for hydrogen, no major technical challenges are expected. In this study, the pressure levels at the output of the electrolysers are assumed to be at 30 bar. This is beneficial because the compression work required to compress from atmospheric pressure to this pressure level is the most energy-intensive part as can be seen in the figure below. Furthermore, it is assumed that the reciprocating compressors will compress from 30 bar to the transmission pipeline inlet pressure of 80 bar.

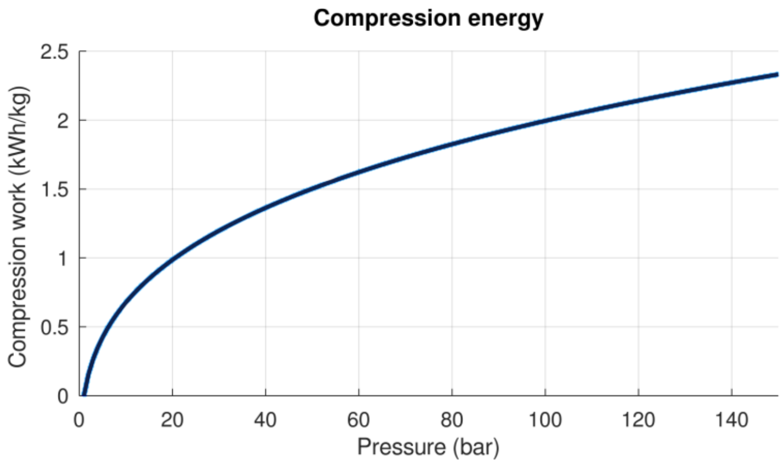


Figure 4-18 - Energy requirement for compressing hydrogen from atmospheric to higher pressure levels (excluding compressor engine inefficiencies)

3.2.7 Pipelines

Pipelines are the most common method for transporting gas and are also expected to be the most commonly used method for transporting hydrogen [1]. Although hydrogen presents challenges such as embrittlement, this is mainly a challenge for re-using existing infrastructure. For new pipelines, hydrogen effects can be taken into account when selecting wall thickness and steel quality. Pipelines are already used for hydrogen transport in the networks of AirLiquide and Air Products and re-use of existing pipes is intensively being developed with some large-scale pilot projects already in operation. Transporting hydrogen through pipelines is an inexpensive and robust method for distances up to 2,000 km, dependent on several factors like the volume of hydrogen transported. Hydrogen has been transported by pipeline since 1938. Between the Rhine and Ruhr areas of Germany a 250–300 mm (9.8-11.8 inch) diameter, 240

[1] EHB-A-European-hydrogen-infrastructure-vision-covering-28-countries.pdf (gasforclimate2050.eu)

km long line constructed of a standard grade of pipe steel has been carrying hydrogen at a pressure of 20–210 bar. By 2020, more than 17 countries had installed hydrogen pipelines with a total length of more than 4,500 km. These pipelines primarily serve refineries and ammonia plants. In the US there is over 2,500 km of hydrogen pipelines already in place. Within Europe, the longest pipelines are in Belgium and Germany, at 600 km and 400 km respectively.

Most hydrogen pipelines have been purpose-built and manufactured in accordance with specific hydrogen codes (e.g. ASME B31.12). ASME B31.12 explicitly states that grades up to X52 / L360 are proven for service in hydrogen gas for onshore applications.

Hydrogen embrittlement is caused by the interaction of hydrogen atoms with the crystal lattices within the steel. The presence of hydrogen enhances the generation of stress corrosion cracks. Steels with body-centred cubic lattice atomic structures (ferritic steels) are susceptible under certain conditions (high tensile stresses in the material). Metals with face-centered cubic lattice atomic structures (e.g. austenitic steels, Al, Ni) are less susceptible.

The likelihood of hydrogen embrittlement taking place in hydrogen pipelines can be reduced by a combination of:

- the lower partial pressure of hydrogen;
- lower temperatures;
- pipeline material selection;
- conservative design (lower hoop stress); and
- minimized pressure cycling.

It is generally recommended that only lower-strength API 5L grades (X52 or lower) should be specified, which keeps the hoop stresses low and allows ‘standard’ pipeline sizes, materials and welding procedures developed for natural gas to be used. Generally, carrying hydrogen in steel pipelines (grades: API 5L-X42 and X52; up to 1,000psi/7,000kPa, constant pressure/low-pressure cycling) does not lead to hydrogen embrittlement. For pressures of 7 bar and lower, non-metallic pipelines (e.g. polyethene, fiber-reinforced polymer) become more cost-effective, especially over long distances.

For offshore pipelines, there are currently no specific pipeline standards or recommended practices for the transport of H_2. There is an ongoing JIP (Joint Industry Project) led by DNV to develop such recommended practice referring to the DNV-ST-F101 Offshore Pipeline code, to which many offshore pipelines are designed.

Due to the lack of existing offshore hydrogen pipelines, there is not yet a best practice for pressure levels. Higher pressures lead to a larger transport capacity (when keeping pipeline diameter fixed) but come at the expense of a larger material requirement (due to increased wall thickness) to withstand the pressure. Furthermore, more expensive steels might be required to prevent hydrogen embrittlement at high pressures. Lastly, higher pressures can only be achieved with additional compression which will also (marginally) increase cost. In DNV’s experience, large diameter pipelines (>36”) with relatively high pressures (50 – 250 bar) yield the most cost-effective transport of hydrogen. For this study, a relatively small diameter pipeline (10.8”) at a pressure of 80 bar was selected as a first estimate for a cost-effective hydrogen pipeline option, primarily driven by the relatively low transport volume compared to typical offshore natural gas pipelines.

3.2.8 Storage

Many wind-to-hydrogen project developers focus on offshore salt caverns for seasonal hydrogen storage, to create a near-flat production profile as often required by industrial end-users. Storage of natural gas in salt caverns has been practised for decades. Salt caverns have also been used to store hydrogen, natural gas, oil, nitrogen and compressed air for decades in Northern Europe, Poland and North America. There are 4 (onshore) hydrogen salt caverns in the world to date, three in the US and one in the UK.

Salt caverns for the storage of Hydrogen are considered the most promising underground storage option for hydrogen, primarily due to the excellent sealing capacity of salt and limited microbial activity to produce unwanted by-products (e.g. H_2S). In addition, lower cushion capacity is required in a salt cavern with faster injection and withdrawal cycles compared to depleted fields or saline aquifers.

Currently, only onshore caverns are used for hydrogen/gas storage and although the offshore aspect provides some novelty, we still expect this to be technically feasible. Offshore drilling is a very mature industry with experience in managing brine as part of offshore O&G developments.

The working capacity of the storage is defined by the stored volume between maximum and minimum pressure. The gas volume below minimum pressure is called cushion gas. Cushion gas is the amount of gas required to maintain the integrity of the cavern. To maximise the storage capacity, higher maximum and lower minimum operating pressures are key operational requirements. Standard guidelines for salt caverns are that the internal pressure must not exceed external pressure, i.e. pressure exerted on the cavern by the surrounding ground (lithostatic or overburden pressure). Exceeding this lithostatic pressure would result in tensile stresses and may fracture salt. Typically, a maximum operating pressure of 10% below lithostatic pressure is reasonable for an adequate safety margin. Please note that this study does not include the cost modelling of hydrogen storage.

3.2.9 Integration of technologies

Overall, the maturity of each individual technology is high or expected to mature towards 2030. However, the integration of each technology into one system is still new. Some pilot projects have started by integrating electrolysis with renewable energy on a small scale but this requires further optimization, development and standardization to roll out on a larger scale. More pilot projects will need to start soon that specifically target the intended concepts for offshore hydrogen production from offshore wind to prove they are technically sound, safe, reliable, compliant, and meet expected performance. The offshore concepts are sensitive to deviations from expected operational performance as offshore maintenance is expensive and time-consuming. Technological development should be closely monitored or should be included in developing the project to assure technical maturity by 2030.

Power supply challenges

One specific aspect that provides technical challenges for the whole integrated system is the islanded operation without (strong) support from the grid. Generally, wind turbines are dependent upon an external grid to start up and remain operational in a stable manner. When turbines operate in isolation from an external grid, this is referred to as *island mode*. Starting up a turbine in island mode is referred to as a *black start*. On a farm level, the *black start* is the starting of a wind farm without the presence of an AC grid to provide a reference frequency and voltage that the turbines can follow. Therefore multiple turbines have to be "grid-forming", in contrast to conventional "grid-following" turbines. Technical possibilities for providing black start capability involve, next-to grid-forming turbines (where the turbine controls the voltage and frequency at its terminals), Battery Energy Storage Systems (BESS), as well as novel concepts such as pumped-hydro in foundation structures. DNV estimates that the ratio of installed power (MW) that would be required to black-start a single turbine is around 0.05 $MW/MW_{turbine}$. The main challenges involve Cable energisation transients, transformer inrush (both can be mitigated by soft energisation), voltage regulation and frequency regulation. Research by Ming Yang Smart Energy (MYSE) has led to the black-starting capability of a MYSE7.25 turbine, which was successfully tested in 2020 [2]. This work was performed in conjunction with DNV's Flex Power Grid Lab in Arnhem, which constructed Hardware in the Loop test rigs for developing wind turbine black start controllers (both for the wind turbine and power converter controllers). Scottish Power Renewables (SPR) has tested the black start capability at the Dersalloch wind farm [3]. There, the turbines were supplied by Siemens Gamesa Renewable Energy (SGRE). DNV has published the report '*Wind power as black start source for network restoration*' [4]. The learnings of this research (using black start capabilities of wind turbines that do have a connection to the grid to provide black start capabilities to other utilities on this grid) are transferrable to turbine OEMs. DNV does not foresee any major technical problems in moving to TRL 9. Furthermore, the additional cost requirements should not be high.

Islanded mode refers to the control and operation of single turbines or entire wind farms that are not directly connected to a synchronized AC grid. These turbines may however be connected to a local AC or DC grid, or by a HVDC transmission to shore. Offshore wind farms connected by HVDC to shore already operate in this way.

The main challenge for the adaptation of these technologies is the wind industries' drive for standardization. If these technologies are not adopted by the turbine OEMs this imposes certification issues for project developers seeking to build black start capable turbines. In this case, an on-site black-start solution will be the most logical solution.

In addition to the start-up capabilities of turbines, electrolysers will also consume power to heat up the system and start producing hydrogen. Moreover, in times of no power generation, critical system elements such as safety equipment, radar equipment and emergency lighting will need to be powered. This requires

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[2] https://www.4coffshore.com/news/mingyang-black-starts-new-turbine-nid17006.html

[3] https://www.scottishpowerrenewables.com/news/pages/global_first_for_scottishpower_as_cop_countdown_starts.aspx

[4] https://www.dnv.com/Publications/wind-power-as-black-start-source-for-network-restoration-185066

a backup system in the form of a battery or a generator (diesel or hydrogen). Further development of such systems is required to tackle this challenge.

Variable power production

The variable generation of renewable energy requires the connected systems to respond to load changes at the same rate. In addition, in times of low generation, the connected systems should be sufficiently capable of operating at low power (sufficient turn-down ratio). Research on this configuration is still lacking but it is expected that both pressurized alkaline and PEM electrolysers can deal with a varying load of wind. This is supported by comparing the ramp rates that could occur in wind farms to the capabilities of the electrolysers.

As a reference, the power output of a 100 MW wind farm -with 750 kW turbines- was studied by NREL [5]. The wind farm was located in the west of Minnesota (US) and the power output was collected for the whole wind farm. Ramp-up and down rates of up to 2.7 %/s were found (excluding outages). Although the average was much lower (0.04%/s), these maximums should still be matched. In comparison, the capabilities of pressurized alkaline and PEM electrolysers are in the order of 20%-100% of load change per second.

It should be noted that this NREL study considers small and likely outdated turbines. Bigger turbines will have more inertia, are located higher (catching more stable winds) and contain AC/DC/AC converters to better cope with power fluctuations. The study furthermore considers onshore turbines, while offshore, the winds might be more stable.

No concerns arise on the minimal operating load as the electrolyser plant will contain numerous stacks which can be shut down individually. One pressurized alkaline stack can operate at a minimum load of 15 – 20%. With 10 stacks, and shutting down 9 of them, the minimum operating load can be reduced to 2%. Even for the integrated concept, the number of stacks is expected to be more than 10 (15 – 20 stacks), resulting in sufficient turn-down capabilities. The effect of variable operation on the lifetime and degradation of the electrolysers however remains unclear. Some manufacturers claim there is no effect while others acknowledge there is an effect but are still evaluating this. References to electrolyser systems running on variable renewable energy are still very limited. Another aspect when shutting down parts of the electrolyser system, whether for operational or safety reasons, is the purge with nitrogen to remove hydrogen from the system and eliminate explosion risks from remaining hydrogen. A nitrogen production and purging system has not been included in the design and manufacturers are still evaluating if this would be needed in an offshore environment. The effect of adding a nitrogen system is assumed to have little effect on the overall design and results as only small systems are needed.

The compressor and water treatment are considered to be capable of sufficient flexibility. The variable power supply from the wind farm will provide some technical challenges and the compressor need to be able to deal with a variable flow of hydrogen. This can be solved by applying a variable drive. This however only provides flexibility within a certain flow range and to provide full flexibility additional hydrogen buffering or a feed-back loop that allows to maintain a more constant pressure difference and hydrogen flow is needed.

No precise data on variable operation of the thermal desalination unit is available but the manufacturer does not expect this to be an issue. The system works with heat exchangers and the water flow can easily be adjusted to accommodate sufficient cooling. For the water supply itself, small buffers will prove a solution with only a minimal impact on costs.

[5] NREL, "Short-Term Power Fluctuations of Large Wind Power Plants," 2002.

3.3 Technology readiness overview

Table 4-3 below summarizes the technical readiness (TRL) of both the onshore and offshore hydrogen production concept and also provides a breakdown of the main technology components. Both the current and the expected state of development are provided. The TRL scheme that has been used is also provided below.

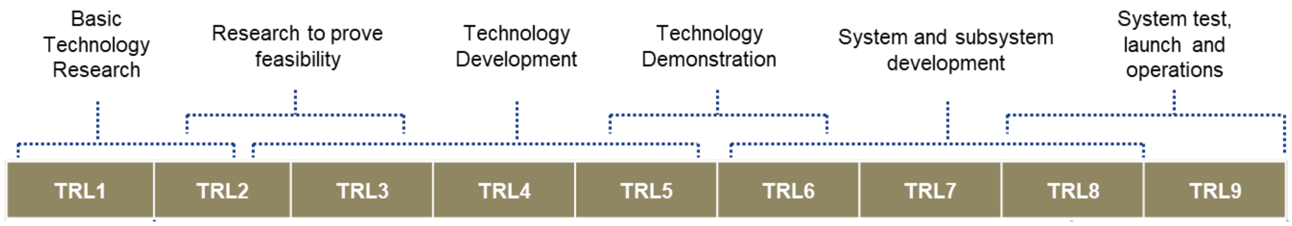


Figure 4-19: TRL scheme for qualification of technology readiness.

<table>
<tr><th>Table 4-3: Summary of technology readiness broken down into main components for both the onshore and offshore hydrogen production concepts</th><th colspan="2">TRL currently</th><th colspan="2">TRL after 2030</th></tr>
<tr><th>Component</th><th>Onshore production</th><th>Offshore Production</th><th>Onshore production</th><th>Offshore Production</th></tr>
<tr><td>Offshore turbines ≥17 MW</td><td colspan="2">7</td><td colspan="2">9</td></tr>
<tr><td>Bottom fixed turbine foundation</td><td colspan="2">9</td><td colspan="2">9</td></tr>
<tr><td>Floating turbine foundation</td><td colspan="2">6</td><td colspan="2">9</td></tr>
<tr><td>Array cables for bottom fixed</td><td colspan="2">9</td><td colspan="2">9</td></tr>
<tr><td>Array cables for floating</td><td colspan="2">7</td><td colspan="2">9</td></tr>
<tr><td>Array pipelines for bottom fixed</td><td></td><td>6</td><td></td><td>9</td></tr>
<tr><td>Array pipelines for floating</td><td></td><td>6</td><td></td><td>9</td></tr>
<tr><td>Bottom fixed substations</td><td>9</td><td></td><td>9</td><td></td></tr>
<tr><td>Floating substations</td><td>5</td><td></td><td>8</td><td></td></tr>
<tr><td>Export cable for bottom fixed</td><td>9</td><td></td><td>9</td><td></td></tr>
<tr><td>Export cable for floating</td><td>7</td><td></td><td>9</td><td></td></tr>
<tr><td>Bottom fixed substructure for H2 production platform</td><td></td><td>9</td><td></td><td>9</td></tr>
<tr><td>Floating substructure for H2 production platform</td><td></td><td>9</td><td></td><td>9</td></tr>
<tr><td>Large scale electrolysis</td><td>5</td><td>3</td><td>9</td><td>8</td></tr>
<tr><td>Desalination and water treatment</td><td>8</td><td>8</td><td>9</td><td>9</td></tr>
<tr><td>Offshore static pipelines for H2</td><td>6</td><td>6</td><td>8</td><td>8</td></tr>
<tr><td>Offshore dynamic pipelines for H2</td><td></td><td>4</td><td></td><td>8</td></tr>
<tr><td>Compression for H2</td><td>9</td><td>6</td><td>9</td><td>9</td></tr>
<tr><td>Offshore salt cavern storage</td><td>7</td><td>7</td><td>8</td><td>8</td></tr>
<tr><td>Integration of technologies</td><td>5</td><td>4</td><td>9</td><td>8</td></tr>
<tr><td>Islanded/remote operation</td><td></td><td>4</td><td></td><td>Unknown</td></tr>
</table>

3.4 Optimised turbine design for hydrogen production

Wind turbines produce power by extracting the kinetic energy of the wind and converting it to electricity. The amount of energy produced depends on the available wind resource at the site and the turbine design. Two of the key parameters in turbine design are rated capacity and rotor diameter. The ratio of rated capacity to the swept area of the rotor is known as turbine-specific power. A turbine with a larger rotor diameter for a given generator capacity (i.e. low specific power) will produce more power at low wind speeds and increase overall energy yield, but the increase in loads and structure associated with a larger rotor diameter increases the CAPEX of the turbine. Conversely, a turbine with a smaller generator capacity for a given rotor diameter (i.e. high specific power) will have reduced loads, and therefore lower CAPEX, but will produce less power at low wind speeds. The effect of increasing or lowering the generator rating on the power curve of a turbine is shown in the figure below.

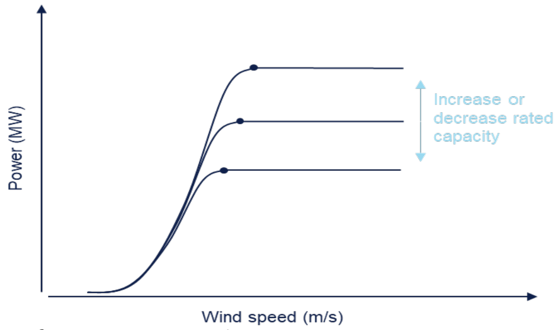


Figure 4-20 - Effect of increasing turbine generator rating at a constant rotor diameter

The power curve of a turbine describes the amount of power it can generate at any given wind speed. A wind turbine starts producing power at a certain wind speed, known as cut-in wind speed, typically around 3-4 m/s. Above this wind speed, the power produced by the turbine will increase roughly in line with the cube of the wind speed. At a certain wind speed, the turbine will reach its rated power. A turbine with a higher rated capacity for a given rotor diameter will reach its rated power output at a higher wind speed, as shown by the different lines in Figure 11 above. Above this wind speed, the power produced is constant and the turbine controller operates to mitigate loads rather than extract more power from the wind. Above a certain threshold, typically around 25-30 m/s, the loads on the turbine become so high that the turbine must stop operation to prevent damage. This is known as cut-off wind speed.

The optimal turbine-specific power for a wind farm is dependent on the wind resource of the site and is not universal across all projects. Offshore wind turbines are currently designed to IEC Class I, denoting the highest mean wind speed, in which the turbines are designed both to survive the conditions associated with such sites, but also with the specific power that gives the lowest LCOE from typical Class I conditions. Onshore turbines may also be designed for lower mean wind speeds (IEC Classes II and III), but this practice has not yet been used in offshore wind, reflecting the historic geographic basis of the offshore wind industry in Europe, which has good wind resources. Offshore turbines designed for lower wind speeds (i.e. with lower specific power) may yet enter the market, and it is noted that machines from Chinese OEMs may also lean in this direction due to the prevailing conditions of Chinese projects.

The power curve of a wind turbine and the wind data can be used to generate a load/power duration curve. This will show how much time a certain power is generated. A simplified representation is provided below. The power generation is limited by the rated capacity of the turbine (as also demonstrated in the power curve) and the area above the rated capacity line is not utilized.

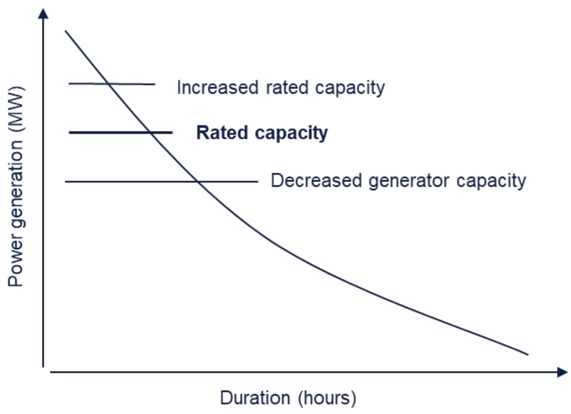


Figure 4-21 - Load/generation duration curve for a wind turbine

For a given turbine design (blades, loads, tower, etc.) it is possible to increase the rated capacity and utilize more of the wind power (area above the rated capacity line) but the turbine will reach a higher capacity for less time. The increase in rated capacity requires a larger generator which adds costs. In addition, all downstream equipment (infield cables, substations, export cables, etc.) should scale accordingly which increases CAPEX even more.

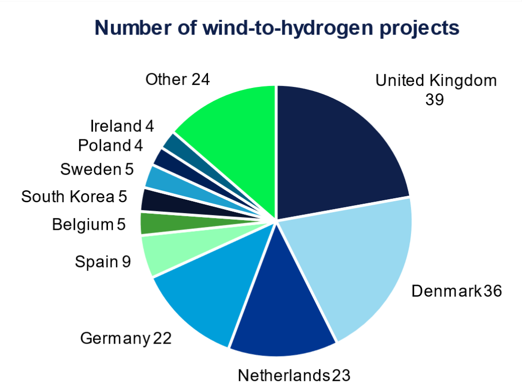
A decrease in generator capacity will have the opposite effect. Less power can be generated but there is a longer period of time at which the turbine generates at full capacity. CAPEX can be saved on the generator and downstream equipment and the utilisation of the equipment increases. Reducing or limiting the generator capacity can be compared with curtailment.

This trade-off is part of the considerations that have to be taken in choosing the correct turbine design and rating and as downstream equipment becomes more expensive, the utilisation becomes more important which can favour a smaller generator capacity. This is the case when introducing an electrolyser that significantly increases the CAPEX.

3.5 Wind-to-Hydrogen pilot projects

As a reference of ongoing wind-to-hydrogen pilot projects, this section shortlists projects from DNV's database – showcasing the most advanced pilot projects of the integrated concept (offshore decentralized topology), centralized platform concept (offshore centralized), and the conventional concept (onshore centralized). In total 176 projects were identified based on public announcements. Many projects are still in the concept/early planning phase, and therefore limited information is available.

The following paragraph will give some descriptive statistics on wind-to-hydrogen projects. As can be seen in Figure 4-22, the majority of these projects are located in Europe. With 39 projects in total, however, the United Kingdom has the largest amount of projects for a single country.



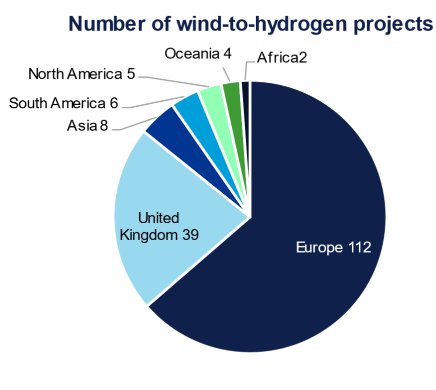


Figure 4-22: Geographical distribution of wind-to-hydrogen projects

As can be seen in Figure 4-23, the large majority of projects where the production topology is known, feature an offshore hydrogen production concept (either centralized or decentralized / hydrogen turbines).

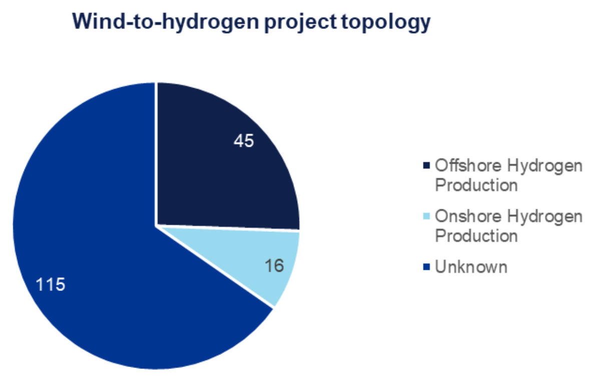


Figure 4-23: Topology choice of wind-to-hydrogen projects

As can be seen in Figure 4-24, out of the projects where the electrolyzer technology is known, many of the projects have selected PEM technology.

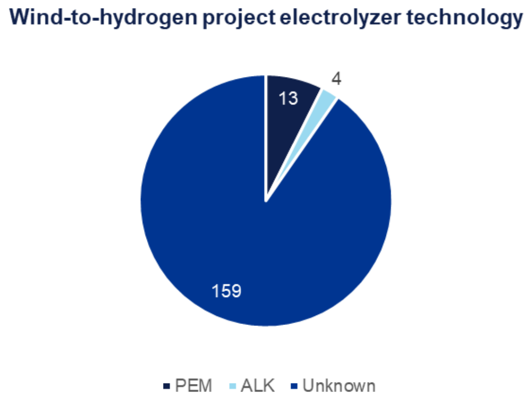


Figure 4-24: Electrolyzer technology choice of wind-to-hydrogen projects

From Figure 4-25 we observe that many of the project developers have selected the year 2030 as the reference starting year for their wind-to-hydrogen project. The year 2024 features the largest peak in the amount of smaller-scale pilot projects that will be deployed.

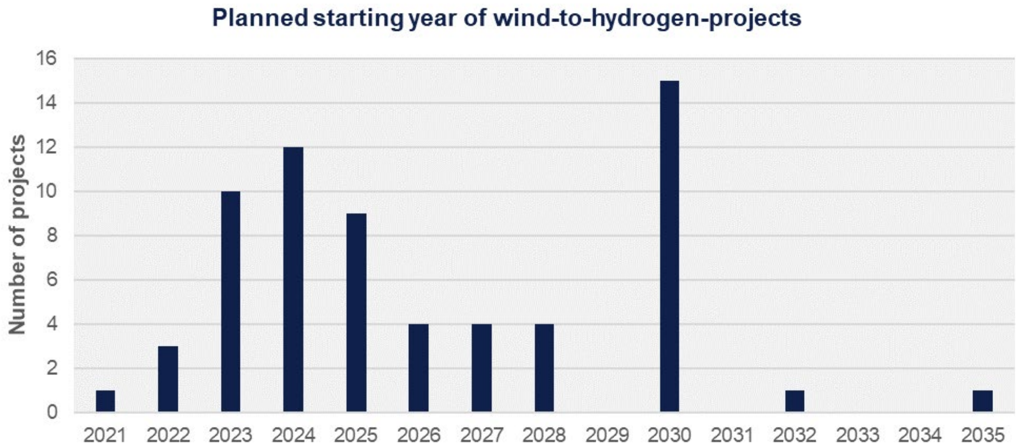


Figure 4-25: Planned starting year of operation for wind-to-hydrogen projects

The next sections will provide more detail on highlighted wind-to-hydrogen (pilot) projects, split between the three production topologies.

3.5.1 Conventional concept – hydrogen production at a centralized onshore plant

Project

H_2RES

Pilot Description

H_2RES is the world's first electrolyser connected directly to offshore wind turbines, forming an integrated setup. The setup will be connected to the transmission grid as well, which requires new, intelligent dispatch algorithms to optimise the value of the setup depending on the market price signals. This solution ensures that external power can be imported during longer periods of low wind power production or exported if the electrical supply/demand situation is tight. Inaugurated in May 2021, the project encompasses several 'state-of-the-art' elements, which had never been seen in this context before.

Figure 4-26: H_2RES Pilot Project

Project Details

- Topology: Onshore centralized
- Wind foundation: Bottom fixed
- Wind capacity: 7.2 MW (2 x 3.6 MW)
- Country: Denmark
- Start operation: 2021
- Project partners: Ørsted, Green Hydrogen Systems, Energinet, NEL, Everfuel , DSV, EUDP and Brintbranchen.
- Electrolyser technology: Pressurized Alkaline
- Electrolyser vendor: Green Hydrogen Systems
- Electrolyser size: 2 MW

The modular electrolyser will be an intelligent N+1 electrolyser solution, which uses smart software and AI to optimize the efficiency of hydrogen production. The hydrogen exiting the electrolyser will go through a high-pressure compressor, which compresses the hydrogen from approximately 30 bar to 350 bar. High compression yields higher energy density and thus reduces storage costs.

Project

Holland Hydrogen One

Pilot Description

With Holland Hydrogen One, Shell aims to produce hydrogen using electricity that has been generated by the offshore wind park Hollandse Kust Noord, which is partly owned by Shell. The renewable hydrogen produced will supply the Shell Energy and Chemicals Park Rotterdam, by way of the HyTransPort pipeline, where it will replace some of the grey hydrogen usage in the refinery. This will partially decarbonise the facility's production of energy products like petrol and diesel and jet fuel.

Figure 4-27: Holland Hydrogen One Project

Project Details

- Topology: Onshore centralized (2030)
- Wind foundation: Bottom fixed
- Wind capacity: 759 MW
- Country: The Netherlands
- Start operation: 2025
- Project partners: Shell Nederland B.V. and Shell Overseas Investments B.V.
- Electrolyser technology: Alkaline
- Electrolyser vendor: ThyssenKrup
- Electrolyser size: 200 MW

The centre of the "Hydrogen Holland I" hydrogen project facility will be a hall, covering 2 hectares, the size of three football fields. Green hydrogen will be produced for industry and the transport sector, with electricity coming from the offshore wind farm Hollandse Kust (Noord), by means of guarantees of origin. The hydrogen can be transported through a pipeline with a length of about 40 kilometers that will run from the plant to Shell's Energy and Chemicals Park Rotterdam. Thyssenkrupp Uhde Chlorine Engineers will engineer, procure and fabricate a 200 MW electrolysis plant based on their large-scale 20 MW alkaline water electrolysis module.

Project

NortH$_2$

Pilot Description

NortH$_2$ is a consortium of Eneco, Equinor, RWE and Shell Netherlands. A recently completed feasibility study demonstrated that large-scale production in the north is possible. Currently, the foundations are being laid for the organisational structure. As a network operator, Gasunie focuses on the assignment it received from the Dutch government to develop the hydrogen backbone.

Figure 4-28: NortH$_2$ Project

Project Details

- Topology: Onshore centralized (2030) – Offshore centralized (2040)
- Wind foundation: Bottom fixed
- Wind capacity: 2027: 1,000 MW – 2030: 4,000 MW – 2040: 10,000 MW
- Country: The Netherlands
- Start operation: 2027
- Project partners: Eneco, Equinor, RWE and Shell Netherlands
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: ~99% of wind farm size

NortH2 focuses on the construction of large wind farms in the North Sea, far off the coast. These can gradually grow from a capacity of 4 GW in 2030 to a capacity of more than 10 GW in 2040. There is also a plan for a large electrolyser in Eemshaven, where wind energy is converted into green hydrogen. The consortium is also considering the possibility of installing electrolysers at sea in a subsequent phase.

Project

FlexH$_2$

Pilot Description

The FlexH$_2$ project will develop innovations that could significantly reduce investment costs for offshore wind transmission infrastructure. The proposed wind-to-hydrogen solution, which will be tested in laboratories at a Medium Voltage kW scale, enables direct sourcing of renewable electricity to green hydrogen production. It is expected to be scalable and can be operated independently from a local or national power grid, thus reducing the time-to-market significantly by 5 to 10 years. The integration of the various proposed innovations – varying from offshore wind turbines to the transport and delivery of power to an onshore electrolyser – could reduce the cost of hydrogen production by at least 10% well before 2030. The results of this research project could provide the basis for the accelerated development of Power-to-H2 projects in the Netherlands.

Figure 4-29: FlexH$_2$ Project

Project Details

- Topology: Onshore centralized
- Wind foundation: N/A
- Wind capacity: N/A
- Country: The Netherlands
- Start operation: 2027
- Project partners: Shell, Van Oord, TKF, TNO, DNV, General Electric, ABB, VONK, Technical University of Eindhoven, and Technical University of Delft.
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: N/A

FlexH2 is based on three key technological innovation pillars:

1. A grid-forming offshore wind farm,
2. A high-performance AC/DC solid-state transformer for large-scale electrolysers,
3. A multi-terminal hybrid HVDC transmission system and its energy system integration.

The project will determine the optimal design and operational solutions for these pillars. FlexH2 will also demonstrate the feasibility and inter-operability of these key technologies at a medium voltage level, which is crucial to boost the confidence of the FlexH2 concept for application in commercial projects. The project will develop the electro-technical innovations and combine these with expertise related to hydrogen electrolysis, balance of plant, market/flexibility, and key component design, transport and installation expertise to bring this technology to the market

Project

$SeaH_2Land$

Pilot Description

$SeaH_2Land$ is a consortium of Ørsted and industrial companies in the North Sea Port cluster in The Netherlands. They have a joint ambition to reduce CO_2 emissions in the Dutch-Flemish industrial cluster with a 1 GW electrolyser. The electrolyser will be linked to a new 2 GW offshore wind farm. ArcelorMittal, Yara, Dow Benelux and Zeeland Refinery support the development of the required regional infrastructure to enable sustainably produced steel, ammonia, ethylene and fuels in the future. This can accelerate substantial CO_2 reductions in the Netherlands and Belgium. This will contribute to achieving the European climate objectives for 2030.

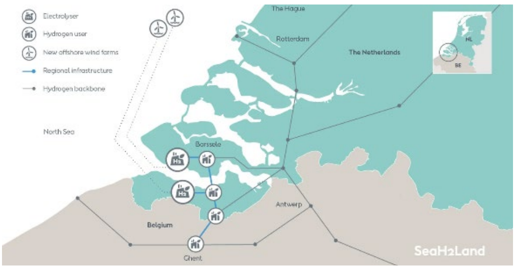


Figure 4-30: $SeaH_2Land$ Project

Project Details

- Topology: Onshore centralized
- Wind foundation: Bottom fixed
- Wind capacity: 2,000 MW
- Country: The Netherlands
- Start operation: Phase 1 asap, phase 2: 2030
- Project partners: Ørsted, ArcelorMittal, Yara, Dow Benelux and Zeeland Refinery
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: 1,000 MW (2 phases of 500 MW)

Project

Chujin

Pilot Description

The Chujin project is a Wind-to-Green Hydrogen project located in South Korea, 10 km east of Chua-do in Jeju City (Southern Jeonang Province). It is aimed to be completed in 2027, with the wind farms constructed in three phases for a total of 1.5 GW capacity. Approximately, there would be 100 wind turbines installed.

Figure 4-31: Chujin Project

Project Details

- Topology: Onshore centralized
- Wind foundation: Bottom fixed
- Wind capacity: 1,500 MW
- Country: South Korea
- Start operation: 2027
- Project partners: Elenergy Co Ltd, DNV, Namsung Shipping
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: N/A

Project

SoutH2Port

Pilot Description

SoutH2Port is a consortium of Skyborn Renewables and industrial companies which aim to create a hydrogen production plant in the Söderhamn municipality in Sweden. They have a joint ambition to reduce CO2 emissions in the Swedish energy system producing hydrogen with a 600 MW electrolyser. The electrolyser will be linked to a new 1 GW offshore wind farm nearby Storgrundet operated by Skyborn Renewables. The new plant will support the decarbonization of the Swedish energy system, either directly with hydrogen supply or by further downstream production of refined fuels such as methanol, sustainable aviation fuel or ammonia – contributing to the government's plans to become the world's first fossil-free welfare country by 2045.

Figure 4-32: SoutH2Port Project

Project Details

- Topology: Onshore centralized
- Wind foundation: Bottom fixed
- Wind capacity: 1,000 MW
- Country: Sweden
- Start operation: 2028 (Wind farm)
- Project partners: Skyborn Renewables, Lhyfe, ABB
- Electrolyser technology: PEM
- Electrolyser vendor: Plug Power
- Electrolyser size: 600 MW

The project is to be located in close proximity to Skyborns' 1 GW offshore wind farm Storgrundet in Söderhamn, Sweden, where Skyborn and Lhyfe recently entered a sales purchase agreement with Stora Enso for an industry property of around 40 hectares. When fully operational, the plant is expected to produce about 240 tons of hydrogen per day, with an installed capacity of 600 MW, making it one of the largest suppliers of renewable hydrogen in Europe.

As part of the Memorandum of Understanding signed between the companies, ABB will apply critical expertise to optimize the integration of hydrogen and electricity production across the entire ecosystem including automation, electrical and digital technologies and drive the development of scalable, commercial energy transition projects in and around the region. The aim is to explore opportunities to tie in Power-to-X conversion technologies turning renewably sourced electricity into carbon-neutral energy carriers, such as hydrogen, and storing the energy for later use.

3.5.2 Centralized platform concept – hydrogen production on an offshore platform

Project

PosHYdon

Pilot Description

PosHYdon seeks to validate the integration of three energy systems in the Dutch North Sea: offshore wind, offshore gas and offshore hydrogen and will involve the installation of the hydrogen-producing plant on the Neptune Energy-operated Q13a-A platform. The Q13a-A is the first fully electrified platform in the Dutch North Sea, located approximately 13 kilometres off the coast of Scheveningen (The Hague).

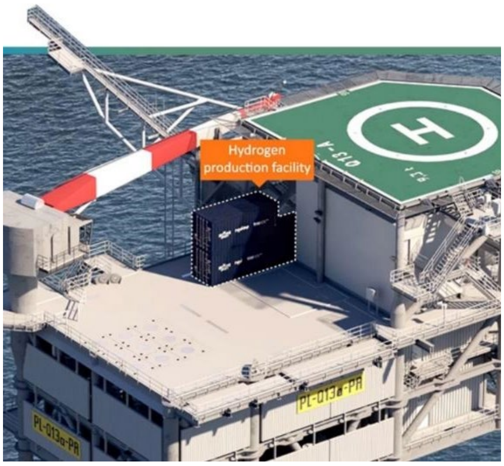


Figure 4-33: PosHYdon Project

Project Details

- Topology: Offshore centralized platform (repurposed platform)
- Wind foundation: Bottom fixed
- Wind capacity: N/A
- Country: The Netherlands
- Start operation: 2024
- Project partners: Neptune Energy, EBN, Eneco, GasUnie, NEL, Emerson, HeatenBoer Water, IV Group, NextStep, NGT, NOGAT, TAQA Offshore, TNO.
- Electrolyser technology: PEM
- Electrolyser vendor: NEL
- Electrolyser size: ~1 MW

Electricity generated by offshore wind turbines will be used to power the hydrogen plant on the Q13a-A platform, converting seawater into demineralized water, and then into hydrogen via electrolysis. The aim of the pilot is to gain experience in integrating working energy systems at sea and the production of hydrogen in an offshore environment. In addition, in this project, the efficiency of an electrolyser with a variable supply from offshore wind will be tested, and at the same time, knowledge and insights on the costs for the offshore installation as well as maintenance costs will be obtained.

Project

H_2opZee

Pilot Description

The H_2opZee project aims to build 300 to 500 megawatts (MW) electrolyzer capacity far out in the North Sea in order to produce green hydrogen, powered by a dedicated offshore wind park.

The hydrogen will then be transported to land via pipeline. The pipeline has a capacity of 10 to 12 gigawatts (GW) and is already suitable for the further roll-out of green hydrogen production to the gigawatt scale in the North Sea. The project is an initiative of TKI Wind op Zee, an initiative supported by the Dutch government that brings people, knowledge and financing together to realise the offshore energy transition in the North Sea. The H_2opZee consortium aims to develop the offshore green hydrogen project in the North Sea before 2030.

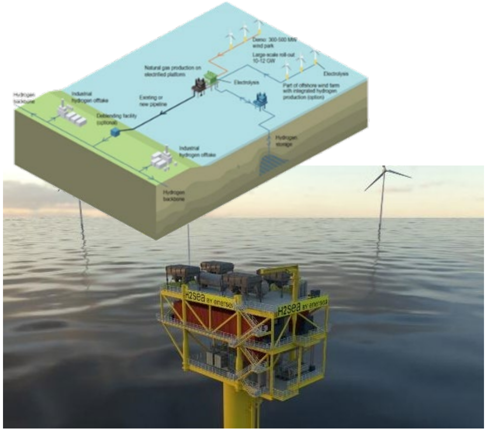


Figure 4-34: H_2opZee Project

Project Details

- Topology: Offshore centralized platform
- Wind foundation: Bottom fixed
- Wind capacity: N/A
- Country: The Netherlands
- Start operation: 2030
- Project partners: Neptune Energy, RWE, H2Sea, Siemens Gamesa
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: 300 – 500 MW

Currently, the feasibility of producing green Hydrogen at sea, powered by offshore wind is being investigated. Different scenarios for producing green hydrogen at sea will be explored, including options for transporting the green hydrogen to shore through a pipeline. H2SEA will advise on all aspects of the design considerations for electrical, processing, utilities, technical safety, structure and its effects on constructability and installation methodology. H2SEA's sister company Enersea has been awarded the pipeline concept design for the feasibility phase of this project.

Project

AquaVentus (AquaPrimus)

Pilot Description

Aqua Primus is the pilot project dedicated to installing two wind turbines (14 MW) off the coast of Heligoland with a hydrogen electrolyser integrated into the base of each turbine tower. Hydrogen is transported from Heligoland to the mainland via a central collector. A share of the hydrogen is retained for use on the island and in shipping. During the first phase of AquaPrimus, a 14 MW prototype (HyStarter) will be deployed in Mukran, Sassnitz in 2023. Following this, two 14 MW pilot turbines will be built in the coastal sea off Heligoland in 2025. AquaPrimus will connect to AquaPortus. AquaPortus is the name given to the incremental and gradual expansion of Heligoland's port infrastructure to accommodate hydrogen. This includes the construction of a LOHC (liquid organic hydrogen carrier) infrastructure to receive and process the AquaPrimus production volume.

Figure 4-35: AquaVentus Project

Project Details

- Topology: Offshore decentralized platform (AquaPrimus), Offshore centralized (AquaSector)
- Wind foundation: Bottom fixed
- Wind capacity: 28 MW
- Country: Germany
- Start operation: 2025
- Project partners: RWE, Ørsted, Equinor, and WindMW, while Shell, RWE, GASCADE, Gasunie, McDermott, Van Oord
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: ~99% of turbine rating

Project

BEHYOND (platform)

Pilot Description

The objective of the BEHYOND project is to develop an engineering conceptual solution and its sub-systems that support the technical-economic model and competitiveness studies of a modular solution to produce hydrogen on a large scale from offshore wind energy.

Figure 4-36: BEHYOND Project

Project Details

- Topology: Offshore decentralized platform
- Wind foundation: Bottom fixed
- Wind capacity: 166% of ELX rating
- Country: N/A
- Start operation: 2025
- Project partners: TechnipFMP, EDP, CEiiA–Engineering and Product Development and WavEC-Offshore Renewables, USN University
- Electrolyser technology: PEM
- Electrolyser vendor: N/A
- Electrolyser size: 200 MW per platform

The 'Multi-centralized Hybrid System' is placed on a dedicated bottom-fixed platform and, being able to produce and export both H2 and electricity, allows higher contractual flexibility and marketability. The use of multiple substations instead of just one not only enables phased investment but also reduces the size of what could potentially be an oversized substation. Moreover, as a hybrid configuration, it balances the pros and cons of both centralized and decentralized configurations. The model results allowed the following general conclusions:

- As a function of wind farm-rated power, net present value improved with increasing size from around 200 MW to 1000 MW,
- Hybrid systems, capable of exporting both hydrogen and electricity, optimised through the solver, saw the highest NPV,
- Hybrid systems that had identical electrolyser and wind farm capacity recorded the lowest NPV, due to under-utilization of electrolysers and electrical equipment such as cabling and grid connection costs,

Moreover, a control system and logic have been developed to accommodate different operating set-points of both the offshore wind farm and the electrolyser according to a combined understanding of external market signals and available wind resources. It focuses on the prioritization between electrolyser stacks in a coordinated manner that contributes to grid stability, and minimization of OPEX in terms of stack efficiency and lifetime.

Project

SeaLhyfe

Pilot Description

The SeaLhyfe project aims to make offshore renewable hydrogen become a reality, by demonstrating the reliability of an electrolyser at sea. The offshore pilot site meets all the necessary conditions – including the presence of Marine Renewable Energy and stringent environmental criteria – to validate the offshore hydrogen production technology before envisaging large-scale industrial deployment in 2024. DNV performed safety studies to identify the key risks.

Figure 4-37: SeaLhyfe Project

Project Details

- Topology: Offshore centralized (floating platform)
- Wind Foundation: Floating
- Wind capacity: 2 MW
- Country: France
- Start operation: 2022
- Project partners: Lhyfe, Plug Power, Chantiers de L'Atlantique, Geps Techno, Eiffage Energie Systemes and, Kraken Subsea Solutions
- Electrolyser technology: PEM
- Electrolyser vendor: Plug Power
- Electrolyser size: 1 MW

The pilot will be operated near the quayside in Saint-Nazaire before being taken 20 km off the coast of Le Croisic to the offshore testing site (SEM-REV) operated by the French engineering school Centrale Nantes. There, it will be supplied with electricity from a floating offshore wind turbine, installed in 2018. The Sealhyfe project will have to meet several major and unprecedented challenges, including:

- Managing the effects on the system of the platform's motion: list, accelerations, swinging movements, etc.;
- Enduring environmental stress: Sealhyfe will have to survive the premature ageing of its parts (corrosion, impacts, temperature variations, etc.);
- Operating in an isolated environment: the platform must operate fully automatically, without the physical intervention of an operator, except for scheduled maintenance periods that have been optimally integrated from the design phase.

SEM-REV / Floatgen is connected to the French power grid via an underwater hub that allows up to three prototypes to be connected simultaneously. This hub is connected to an electrical station onshore via an 8 MW cable.

Project

HyMed

Pilot Description

The HyMed project will be the world's largest floating offshore wind and green hydrogen production asset. The project will have a total 3.2GW capacity, with more than 1GW allocated to produce green hydrogen. At over 300 km offshore, the site will float in ultra-deep waters, nearly 2,900 meters above the seabed. From the start, the project has set out for this to act as a template for future green hydrogen production. For the template to be globally applicable, the design must be practicably executable in a broad range of locations. The simple solution is to build smaller minimalist green hydrogen modules that can be rapidly manufactured, transported and assembled by small yards and minimal facilities. To achieve this, Aquaterra Energy will use its learnings from delivering adaptable and modular platform solutions under the name Sea Swift.

Figure 4-38: HyMed Project

Project Details

- Topology: Offshore centralized
- Wind Foundation: Floating
- Wind capacity: 3,200 MW
- Country: Italy
- Start operation: 2027
- Project partners: Aquaterra Energy, Seawind Ocean Technology
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: 1,000 MW

The Sea Swift platform concept has been used by operators all over the world to solve complex field development challenges and scenarios, all whilst reducing capex, emissions, and time to production. By applying the same intelligent engineering expertise to address key offshore green hydrogen challenges, the team will further future-proof the design for years to come.

Project

Haldane

Pilot Description

The project Haldane involves the deployment of an electrolyser system on a converted jack-up rig and powering hydrogen production with the electricity produced by offshore wind turbines installed in the North Sea. As remote locations create challenges around grid connectivity and intermittency of supply, this solution will overcome the issue by providing an offtake point for the electricity produced in the immediate vicinity of an offshore wind farm and aims to use existing platforms, pipelines, terminal infrastructure, and offshore equipment leveraging the existing infrastructure to reduce costs.

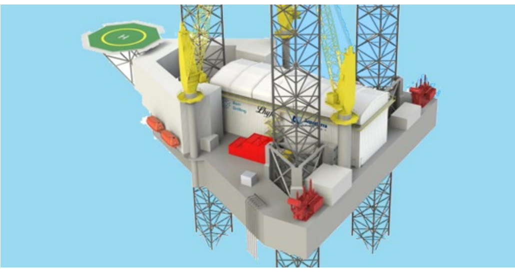


Figure 4-39: Haldane Project

Project Details

- Topology: Offshore centralized
- Wind Foundation: Floating
- Wind capacity: N/A
- Country: N/A
- Start operation: >2025
- Project partners: Aquaterra Energy, Borr Drilling, Lhyfe
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: N/A

Haldane provides an opportunity to reuse existing large oil and gas capital hardware for new uses as the energy transition takes hold – reducing the carbon footprint of creating new offshore structures and supporting the life extension and repurposing of existing assets, from drilling rigs through to onshore terminal facilities. In addition to this, it offers the potential to repurpose existing skills within the oil and gas workforce for innovative clean energy production. The jack-up rig allows green hydrogen projects to go pretty much anywhere bottom-fixed offshore wind projects can.

The next stage of the project is to perform a FEED (Front End Engineering Design) study to develop the technical details that lead into the detailed design phase. It is estimated that the first industrial-scale hydrogen production unit could be operational offshore North Sea by 2025.

Tender

Ten noorden van de Waddeneilanden

Pilot Description

The world’s first offshore wind tender that explicitly includes hydrogen production. The site has been chosen by the Dutch government for the world's largest offshore wind-to-hydrogen project. The wind farm has approximately 500 MW of electrolysis capacity and should be operational around 2031. The existence of the wind farm and an existing natural gas pipeline has made the location an appropriate choice for connection to the onshore hydrogen network.

As a stepping stone to this project, work is also underway on a smaller pilot with an electrolysis capacity of around 50 – 100 MW. This should get the first flaws out of the technology so that the 500 MW project can be realised efficiently. Later in 2023, the minister intends to choose a preferred location for this smaller project as well.

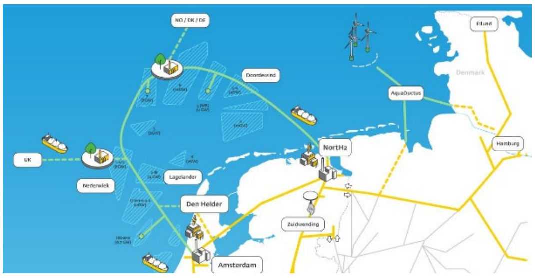


Figure 4-40: Ten Noorden van de Waddeneilanden – Dutch offshore H2 tender

Project Details

- Topology: Offshore centralized
- Wind foundation: Bottom fixed
- Wind capacity: 700 MW
- Country: The Netherlands
- Start operation: 2031
- Project partners: N/A
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: 500 MW

Before the tenders are issued, the ministry is carefully working out a number of important issues together with the Groningen region, parties around the Wadden region and stakeholders. Such as the landfall of the pipeline to bring hydrogen from the wind farm ashore and how hydrogen production can be done safely and ecologically.

This is the first project that will connect to Gasunie’s offshore hydrogen transport network. This network will bring large quantities of hydrogen on land and will be connected to the hydrogen network on land. In 2023, the Dutch government will work out what the hydrogen network at sea should look like, taking into account the extent to which the reuse of existing gas infrastructure in the North Sea is feasible.

Project

AmpHytrite

Pilot Description

The partners of the AmpHytrite project will investigate the end-to-end process: from the green electrons provided by the wind turbine generator (WTG) to the required offtake profile for the onshore hydrogen customer. The project aims to establish a demonstration project to validate that a fully commercial offshore, off-grid centralized green hydrogen wind farm project could be feasible.

A small-scale (DNV estimate 5 MW, producing approx. 750 tons of green H2 per annum) onshore unit at Sif's Maasvlakte 2 terminal is foreseen to be installed, solely powered by the Haliade turbine on site, as if being offshore and off-grid, taking on the full complexity of the offshore and off-grid operation, whilst being installed onshore at the Sif terminal.

Figure 4-41: AmpHytrite Project

Project Details

- Topology: Offshore centralized
- Wind foundation: Bottom fixed
- Wind capacity: 14 MW (Haliade-X)
- Country: The Netherlands
- Start operation: 2024
- Project partners: Sif Group, KCI the engineers, GE Renewable Energy and Pondera.
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: N/A (5 MW estimate)

The memorandum of understanding provides for three phases. The three phases identified in the AmpHytrite project are:

- Conducting a feasibility study into offshore off-grid production of green hydrogen.
- The development and construction of a small-scale onshore production unit at the Sif factory on the Maasvlakte. It will run exclusively on the power generated by the Haliade wind turbine. The demonstrator will be operational in 2023 and produce a maximum of 750 tons of green hydrogen per year.
- The proof of concept from the second phase will be scaled up to a total wind farm size of full scale, offshore and off-grid.

3.5.3 Integrated concept – hydrogen production at the offshore turbine

Project

Deep Purple

Pilot Description

The main purpose of the Deep Purple technology ecosystem is to provide power to offshore off-grid customers such as offshore installations and remote island builds. It can offer stable power, with hydrogen stored as a high-capacity battery and re-electrified to deliver stable, renewable, and scalable energy in the ocean space.

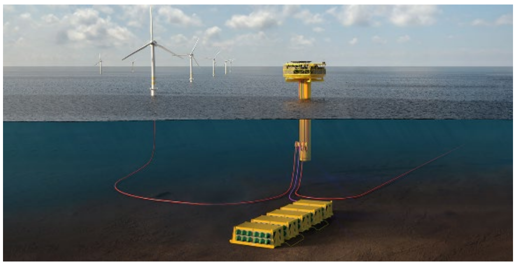


Figure 4-42: Deep Purple Project

Project Details

- Topology: Offshore decentralized platform (floating)
- Wind foundation: Any
- Wind capacity: N/A
- Country: Norway
- Start operation: 2024
- Project partners: Technip FMC, Vattenfall, Repsol, Slåttland, NEL, UMOE Advanced Composites, ABB, DNV, SINTEF, University of South East Norway, Energy Valley, Ocean Hyway Cluster and GCE Ocean Technology
- Electrolyser technology: PEM / Alkaline
- Electrolyser vendor: NEL
- Electrolyser size: 1 – 20 MW

Currently, the project consortium is designing, building, and testing a physical, land-based pilot at TechnipFMC's Norwegian headquarters in Kongsberg. The pilot will include an electrolyser, hydrogen storage, fuel cells, and energy control system as well as the development and testing of an advanced control and advisory system and a dynamic process simulator. The pilot will allow the consortium partners to ensure energy efficiency and autonomous operation offshore, as well as prepare the system for large-scale offshore commercial use.

Excess wind power is used to split water into hydrogen and oxygen by electrolysis. Fresh water for the electrolysis process is produced from seawater using reverse osmosis. This pilot project stands out in one aspect: The hydrogen is sent down to the seabed where it is stored under pressure – subsea compressed hydrogen storage (60 – 100 ton H2). During periods when wind energy cannot satisfy demand, fuel cells will convert the stored hydrogen back into electricity, supplied in the same cable to the consumer.

Further steps of the pilot project include a coastal pilot of 1 – 2 MW (2024), a large-scale offshore demonstration plant: of 2 – 5 MW (2026) as well as commercial solutions for Renewable and stable power to remote islands or oil & gas platforms (10 – 20 MW), offshore hydrogen production (10 – 20 MW).

Project

Brande Hydrogen

Pilot Description

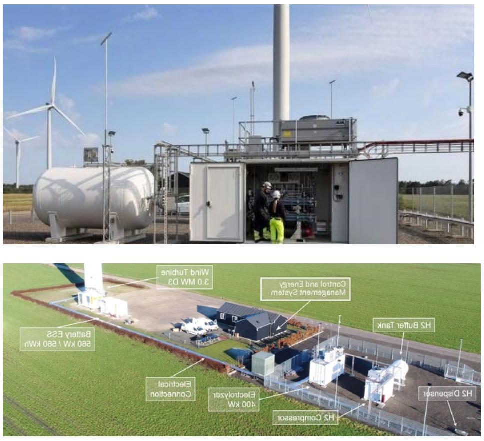


Figure 4-43: Brande Hydrogen Project

The Brande Hydrogen project has been the first in the world to produce green hydrogen from an onshore wind turbine connected to an electrolyzer. The focus areas of the project have been the development of an integrated safety standard for wind-to-hydrogen systems, an integrated Energy Management System (EMS), practical learnings of the world's first direct coupling of a wind turbine to an electrolyser and identifying technical, legal and commercial challenges and strategies for scaling up the technology.

Project Details

- Topology: Offshore decentralized (onshore pilot)
- Wind foundation: Bottom fixed
- Wind capacity: 3 MW
- Country: Denmark
- Start operation: 2023 (onshore pilot)
- Project partners: Siemens Gamesa, Siemens Energy
- Electrolyser technology: PEM
- Electrolyser vendor: Siemens Energy
- Electrolyser size: 400 kW

Project

Nerehyd

Pilot Description

France-based green hydrogen technology developer Lhyfe and engineering company DORIS have signed a Memorandum of Understanding (MoU) on working together on offshore hydrogen production projects, with a plan to launch the first floating wind turbine for integration with a hydrogen production system. The partners will work on finalising the development of their proprietary solution called Nerehyd, which combines Lhyfe's renewable hydrogen production expertise with DORIS' floating wind turbine solution Nerewind. The solution incorporates a hydrogen production facility into the floater of a wind turbine and could be deployed for on-grid or off-grid applications, from single 10 MW wind turbines to large-scale wind farms with several hundred megawatts of capacity, according to the new partners.

Figure 4-44: Nerehyd Project

Project Details

- Topology: Offshore decentralized (floating turbine)
- Wind Foundation: Floating
- Wind capacity: 10 MW
- Country: France
- Start operation: 2025
- Project partners: Lhyfe, DORIS, Strohm,
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: 10 MW

The Netherlands-based thermoplastic composite pipe (TCP) manufacturer Strohm and French renewable hydrogen supplier Lhyfe have signed a memorandum of understanding (MoU) to cooperate on developing solutions for onshore and offshore hydrogen transport, with initial plans to launch the first floating wind turbine to be integrated with a hydrogen production system.

Project

Hydrogen Turbine 1 (HT1)

Pilot Description

HT1 is a pilot project proposed to demonstrate an offshore decentralized platform in one of Vattenfall's existing windfarm – Aberdeen Offshore Wind Farm (AOWF). The concept of the project is to attach an electrolyzer into one of its turbines initially (8.8 MW per turbine), which afterwards will be producing green hydrogen using seawater and electricity from the wind turbine itself. The resulting hydrogen will then be conveyed to the shore via a pipeline and utilized as an eco-friendly energy resource.

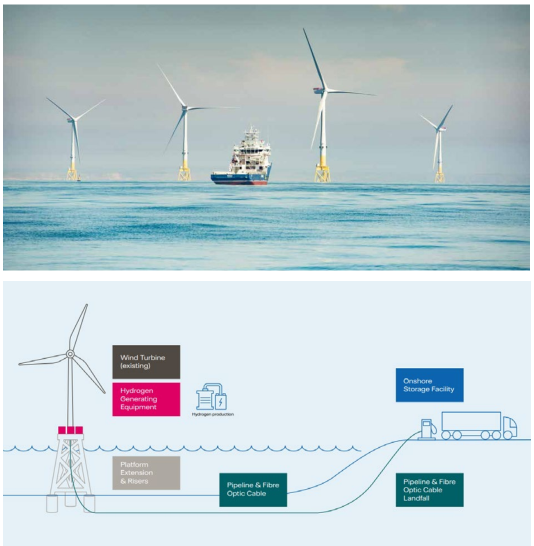


Figure 4-45: H1T1 Project

Project Details

- Topology: Offshore decentralized platform
- Wind foundation: Bottom fixed
- Wind capacity: 97 MW (8.8 MW x 11 Turbines)
- Country: Scotland
- Start operation: 2025
- Project partners: Vattenfall
- Electrolyser technology: N/A
- Electrolyser vendor: N/A
- Electrolyser size: N/A

Project

OYSTER

Pilot Description

The OYSTER project will lead to the development of a combined wind turbine and electrolyser system designed for operation in marine environments. The electrolyser system will be designed to be compact, to allow it to be integrated with a single offshore wind turbine, and to follow the turbine's production profile. Furthermore, the electrolyser system will integrate desalination and water treatment processes, making it possible to use seawater as a feedstock for the electrolysis process. ITM Power is responsible for the development of the electrolyser system and the electrolyser trials, while Ørsted will lead the offshore deployment analysis, the feasibility study of future physical offshore electrolyser deployments, and support ITM Power in the design of the electrolyser system for marination and testing. Siemens Gamesa Renewable Energy and Element Energy are providing technical and project management expertise.

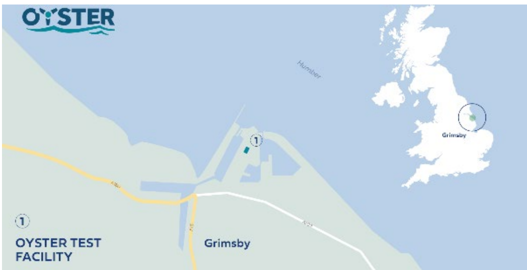


Figure 4-46: OYSTER Project

Project Details

- Topology: Offshore decentralized
- Wind foundation: Bottom fixed
- Wind capacity: N/A
- Country: United Kingdom
- Start operation: 2025
- Project partners: ITM Power, Ørsted, Siemens Gamesa and Element Energy
- Electrolyser technology: PEM
- Electrolyser vendor: ITM Power
- Electrolyser size: Multi MW

The OYSTER consortium selected Grimsby because of the region's strong connection to renewable energy, in particular offshore wind. Grimsby is home to the O&M hub for Ørsted's UK East Coast operations, including Hornsea One and Hornsea Two, which will be the world's largest offshore wind farm when completed in 2022. Both offshore wind farms use Siemens Gamesa turbines and are fitted with blades manufactured in Hull. The Humber is also home to Gigastack which is developing a blueprint for the deployment of industrial-scale renewable hydrogen from offshore wind. The Gigastack project is led by a separate consortium, consisting of ITM Power, Ørsted, Element Energy and Phillips 66 Limited.

Project

H_2 Mare

Pilot Description

The H_2Mare project aims to produce green hydrogen from offshore wind renewable electricity. The project intends to integrate water electrolyzers directly into the wind turbines. By doing so, the hydrogen production cost can be minimized since no connection to the grid is needed. Therefore, offshore production of hydrogen using this topology allows for a larger amount of sea area available for wind energy generation. The project features process design and development followed by an onshore test setup. Co-located with this test setup, high-temperature electrolysis (HTE) and seawater electrolysis will be tested, as well as processes-coupling by means of redeploying the waste heat from the electrolysis efficiently to desalinate seawater. This purified water is required to produce hydrogen offshore. The result is improved efficiency in the offshore production of hydrogen. To achieve this goal, a test infrastructure is planned to expand the Hydrogen Lab in Bremerhaven.

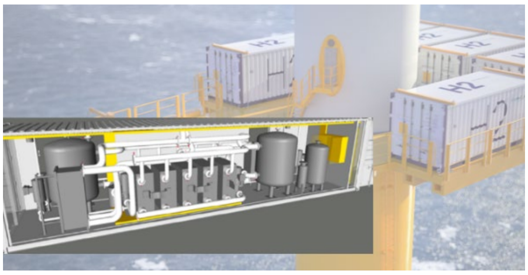


Figure 4-47: H_2 Mare Project

Project Details

- Topology: Offshore decentralized
- Wind foundation: Bottom fixed
- Wind capacity: N/A
- Country: Germany
- Start operation: 2024 (onshore pilot)
- Project partners: Siemens Gamesa, Siemens Energy, RWE, Fraunhofer, DECHEMA, KIT IMVT
- Electrolyser technology: PEM
- Electrolyser vendor: Siemens Energy
- Electrolyser size: ~100% of wind turbine size

The aim of the onshore pilot is to mimic and investigate the effects of offshore conditions in the upscaling chain from cell to megawatt systems. Test profiles are currently under development which replicates the offshore production of hydrogen realistically. The optimal technical integration of the complete system, including the control procedures, will be considered. The PEM electrolysis will be further developed with a focus on offshore conditions, including the investigation of materials and degradation.

In addition, the project will also explore the production of hydrogen derivatives (i.e. offshore power–to–X such as ammonia). Novel technologies will be explored as well, which include steam and seawater electrolysis for producing green hydrogen offshore. Safety, environmental concerns, technology evaluations, and life cycle assessments will also be addressed to guarantee project success.

Project

BEHYOND (decentralized floater)

Pilot Description

The objective of the BEHYOND project is to develop an engineering conceptual solution and its sub-systems that support the technical-economic model and competitiveness studies of a modular solution to produce hydrogen on a large scale from offshore wind energy.

The 'Decentralized Hydrogen Only System' is designed to be hosted directly on the wind turbine floating platforms. It eliminates the need for large electrical substations and the extremely expensive HVDC cables, as the piping converges into a subsea manifold which will export hydrogen to land through a single pipe. Moreover, the required electrolyser capacities are convenient like the current state-of-the-art thus easing phased investment.

Figure 4-48: BEHYOND Project

Project Details

- Topology: Offshore decentralized
- Wind Foundation: Floating
- Wind capacity: 10.6 MW
- Country: N/A
- Start operation: 2025
- Project partners: TechnipFMP, EDP, CEiiA–Engineering and Product Development and WavEC-Offshore Renewables, USN University
- Electrolyser technology: PEM
- Electrolyser vendor: N/A
- Electrolyser size: 10.0 MW

The model results allowed the following general conclusions:

- As a function of wind farm-rated power, net present value improved with increasing size from around 200 MW to 1000 MW,
- Increases in distance from shore resulted in larger decreases in NPV for hybrid systems, with extra costs incurred for longer pipelines and especially export cables,
- Pipeline costs per kilometre were lower than the cable costs, so hydrogen-only systems with no export cables had smaller cost increases and were the most financially viable option at distances greater than 130km.

3.5.4 Novel concepts – The future of offshore energy production

In recent years, there has been a growing interest in offshore hydrogen production as a promising avenue for renewable energy storage and decarbonization efforts. Several novel concepts have emerged, leveraging various technologies to harness the power of wind, solar, tidal, and wave energy. These concepts include coupling floating wind farms to Floating Production, Storage, and Offloading (FPSO) vessels where electricity is converted to hydrogen, ammonia, or even carbonous molecular energy carriers such as methanol. Furthermore, concepts that integrate hydrogen production with floating wind turbines, ones that utilize floating solar arrays, and explore deep-sea storage and electrolysis have been identified. These developments not only hold the potential to open up an area of unprecedented potential for renewable energy generation (far) offshore but could also contribute to a sustainable and cleaner future.

- One significant concept is the coupling of floating wind farms with FPSO vessels. This approach involves electrically coupling offshore wind turbines with Power-to-X production facilities on a ship. This configuration allows the wind turbines to generate electricity, which is then used to power the electrolysis process for hydrogen production and other subsequent synthesis steps. The produced hydrogen, ammonia, and methanol (or other) can be stored onboard the FPSO vessel and later transported to shore for various applications. DNV has already provided the first Approval in Principle statement for such a concept [6], making it likely that it is possible to reach TRL 9 within one decade.

Figure 4-49: Artists impression of the NH3 FPSO concept - a floating ammonia production unit developed by SWITCH2 and BW Offshore

- Another promising development is the integration of hydrogen production with floating wind turbines themselves. These turbines are equipped with electrolysis systems, which directly convert the electricity generated by the turbines into hydrogen. The generated hydrogen can either be stored on the turbine or transported to a nearby storage facility for further use. In general, DNV experiences a wider variety of design concepts among floating wind turbines with integrated hydrogen production. A logical result given the development status of floating wind turbine technology itself, a dominant concept (such as the three-blade bottom fixed turbine) has not yet emerged.

[6] https://www.dnv.com/news/dnv-awards-aip-for-a-floating-ammonia-production-unit-developed-by-switch2-and-bw-offshore--240876

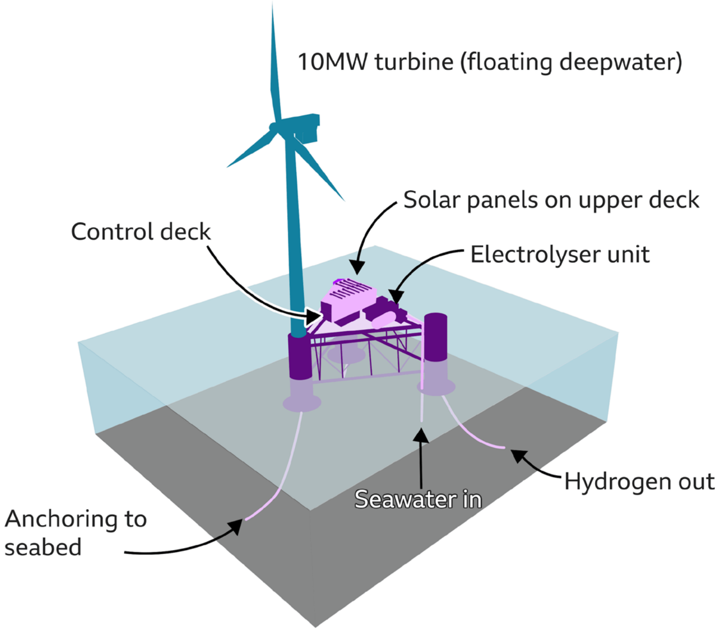


Figure 4-50: Artist's impression of the ERM Dolphyn concept - a floating wind turbine plus hydrogen production unit

- Floating solar arrays have also emerged as a technology for offshore hydrogen production. These arrays consist of photovoltaic panels mounted on floating platforms, such as pontoons or barges, deployed in offshore waters. The solar panels harness solar energy to generate electricity, which is then used for hydrogen production through electrolysis. Although the concept is relatively new, several pilot projects are exploring the potential of floating solar for hydrogen production. These projects will provide valuable insights into the technical and economic feasibility of the concept. It may take a few more years of testing, optimization, and cost reduction before such projects reach TRL 9 and become commercially viable.

Figure 4-51: Pilot project for floating solar by Oceans of Energy in the Dutch North Sea

- In addition to wind and solar energy, tidal and wave energy can be harnessed for offshore hydrogen production. These renewable sources offer a predictable and continuous energy supply, making them suitable for consistent hydrogen production. Several projects are underway to explore this potential. The European Marine Energy Centre (EMEC) in Orkney, Scotland, is conducting research and testing programs on tidal and wave energy devices, including their integration with hydrogen production systems. This research contributes to the development of innovative technologies that combine marine energy and electrolysis for offshore hydrogen production. Due to the complex nature of tidal and wave energy systems and the need to optimize their integration with hydrogen production, it may take several more years, potentially a decade or longer, for these concepts to mature and reach TRL 9.

Figure 4-52: Pilot project for tidal energy-based hydrogen production by Nova Innovation in Scotland

- Deep-sea storage and electrolysis represent another frontier in offshore hydrogen production. This concept involves deploying electrolysis systems and hydrogen storage infrastructure at great depths, leveraging the vast open spaces available in the ocean. Given the complexity of operating at great depths, the need for extensive research and development, and the potential regulatory considerations, it is likely to take a considerable amount of time, possibly more than a decade, for deep-sea hydrogen production concepts to reach TRL 9 and be ready for commercial rollout.

The timeline for the development of novel offshore hydrogen production concepts can vary depending on several factors, including the technology readiness level (TRL), regulatory frameworks, market demand, and investment availability. Achieving TRL 9, which signifies commercial rollout, typically requires overcoming technical challenges, conducting extensive testing, and ensuring scalability and cost-effectiveness.

It's important to note that these timelines are speculative and subject to various factors that can accelerate or delay technology development. Advances in materials, manufacturing techniques, and supportive policy frameworks can expedite the process. Additionally, increased investment and collaboration among industry stakeholders, research institutions, and governments can play a vital role in accelerating the path to commercial rollout for offshore hydrogen production concepts.

4 OFFSHORE WINDFARM CONCEPT DESIGN

The objective of this study is to develop a techno-commercially viable conceptual design for a 1 GW offshore wind farm in each of Gujarat and Tamil Nadu for green hydrogen production. Based on a Strategy paper published by MNRE [8], Zone under model 3 (B1, B2, B3, B4 & G1) for Tamil Nadu and only Zone B3 under model 1 in Gujarat was considered for initial screening. The below section details the concept design for different elements of offshore wind farms.

4.1 Site Screening

Preliminary studies carried out by NIWE across the coastline of India indicate good potential both off the Southern tip of the country and the West coast for offshore wind farm development in India. The offshore wind potential was assessed by the FOWIND (Facilitating Offshore Wind in India) consortium with DNV as a technical partner. Based on a multi-criteria approach involving the assessment of various parameters such as wind resource, bathymetry etc., eight zones each off the coast of Gujarat and Tamil Nadu were identified as potential offshore wind energy zones. The identified eight zones off the coast of Tamil Nadu & Gujarat and their locations are shown in Figure 5-1.

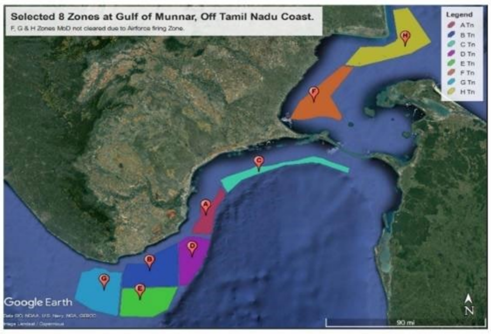


Figure 5-2 shows the further refinement of zone boundaries undertaken by MNRE/NIWE for tendering purposes which are described in the strategy paper.

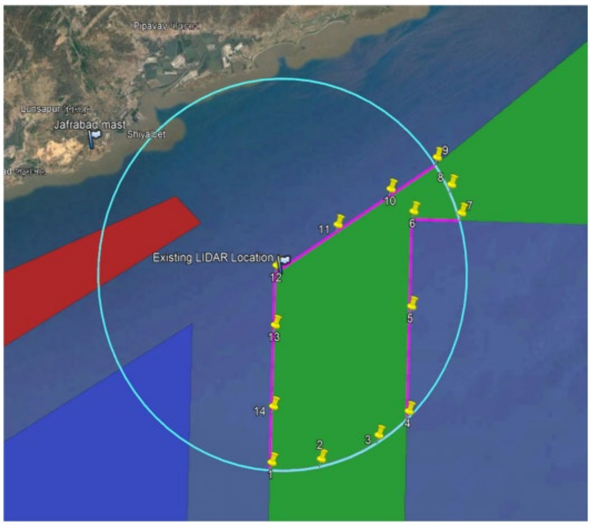


Figure 5-2 Blocks considered for Initial tendering in Tamil Nadu (L) and Gujarat (L)

DNV has undertaken a high-level LCoE-based screening for shortlisting 1 zone out of 5 for the concept design based on LCoE.

Table 5-1 Zone Parameters considered for LCoE modelling In Tamil Nadu

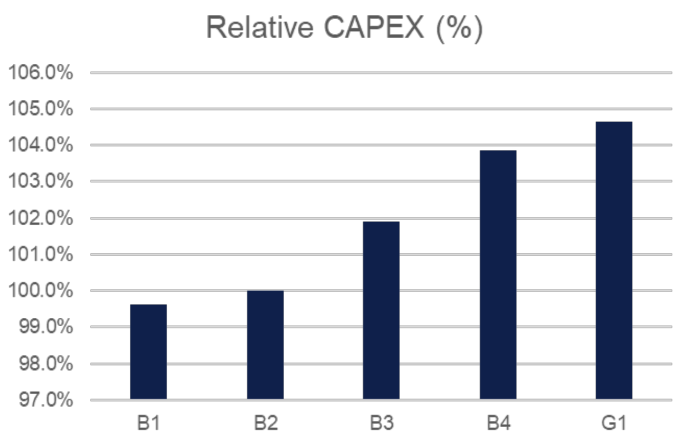
Parameter	B1	B2	B3	B4	G1
Average Annual Mean Wind speed (m/s) @ 150 m	10.9	10.9	10.4	10.0	9.0
Water Depth (m)	29	26	32	42	43
Distance to Tuticorin (construction) port (km)	110	90	100	115	145
Distance to Chinnamuttom (O&M) port (km)	20	31	35	30	30

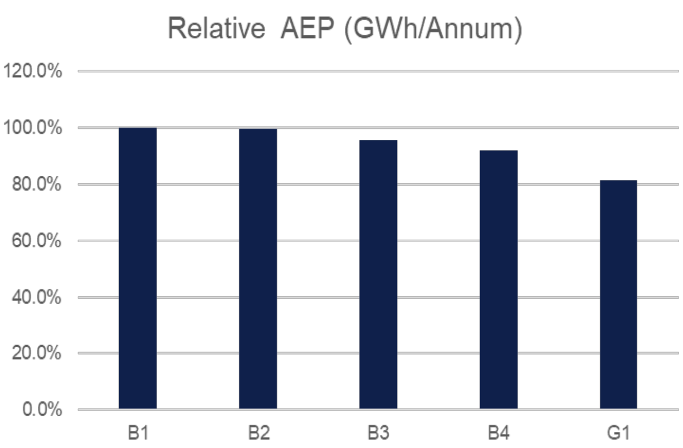
DNV performed LCoE analysis using the proprietary Renewable. Architect software with the above-mentioned assumptions as input. Results are reported as relative values since the purpose of the screening is the elimination of sub-optimal zones; absolute values will be provided in later parts of this report.

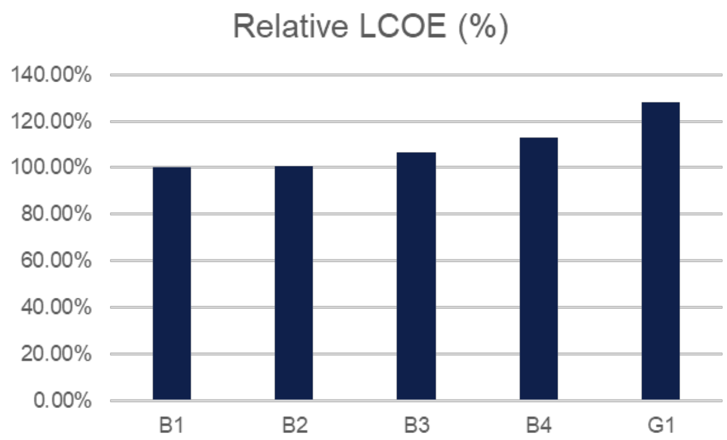
The relative LCoE trends across zones are shown in Figure 5-3 below. The CAPEX is highest for the wind farm in zone G and lowest for the wind farm in zone B1. While the turbine CAPEX is similar across the zones, the primary driver for the differences is the foundation and the electrical CAPEX which depend upon the water depth and the distance to the shore/grid sub-station.

The wind farm in zone B1 & B2 shows the highest energy numbers with zone G being the lowest. This is primarily driven by the mean wind speeds of the zone.

Conclusion of this screening results in Zone B1 being the most optimized in terms of LCoE hence it is selected for concept design.







4.2 Turbine Technology

The size of offshore wind turbines has been steadily increasing over the years, driven by advancements in technology, improvements in manufacturing processes, and a desire for greater efficiency and cost-effectiveness. The trend towards larger turbines has several advantages. Larger turbines can generate more electricity per unit, reducing the number of turbines needed to meet a given energy demand. They can also operate more efficiently at higher wind speeds, increasing the amount of electricity they can generate over time. Finally, larger turbines can be more cost-effective, as they require fewer foundations and support structures, reducing the overall cost of installation and maintenance.

There are several players in the offshore wind market some of whom have a global presence while some are restricted to specific regions. The offshore turbine supply market is generally dominated by OEMs catering to the Chinese and European markets. Most of these OEMs also have a significant presence in the global onshore wind market which has been an enabling factor in speeding up the maturity of the offshore wind market in Europe and China. India-based established onshore turbine manufacturers such as Suzlon, Inox, etc. do not have a presence in the offshore wind sector presently.

Table 5-2 shows the latest product offerings /Announcements from Western and Chinese OEMs. It is evident from the data industry is moving towards a 15+ MW turbine model in the near future.

Table 5-2 Latest Offshore wind turbine from Western & Chinese OEM (s)

Model	Company	Nameplate capacity (MW)	Serial production year	Rotor Diameter (m)	W/m2
SG 14-220 DD	Siemens Gamesa	14 MW	2024	220	368
SG 14-236 DD	Siemens Gamesa	14 MW	2024	236	320
Haliade-X	General Electric	14 MW	2024	220	368
V236-15.0	Vestas	15 MW	2025	236	343
MySE 16.0-242	MingYang	16 MW	2026	242	348
MySE 18.0-28X	MingYang	18 MW	-	28X	-
H260-18MW	CSSC	18 MW	-	260	340

DNV performed an indicative turbine size optimisation analysis considering a generic 1 GW wind farm concept. Figure 5-4 below demonstrates the LCoE heatmap with various turbine sizes.

- The LCoE heatmap shows that the LCoE reduces with increasing turbine rating for a given power density/rotor productivity.
- LCoE broadly decreases with increasing turbine-rated power for a given rotor productivity.
- The lower end of LCoE is seen in the turbine sizes towards the higher end of the rated power range (>16 MW) and towards the higher end of the rotor productivity range (> 350 W/m2).
- The LCoE is seen to decrease with increasing turbine size because of the decrease in the foundation and the array cable cost per MWh on account of the lower number of turbines required.
- The rate of LCoE reduction beyond 18 MW starts to gradually saturate showing that while larger turbine models tend to be lower in LCoE the reduction tends to be marginal beyond a point.

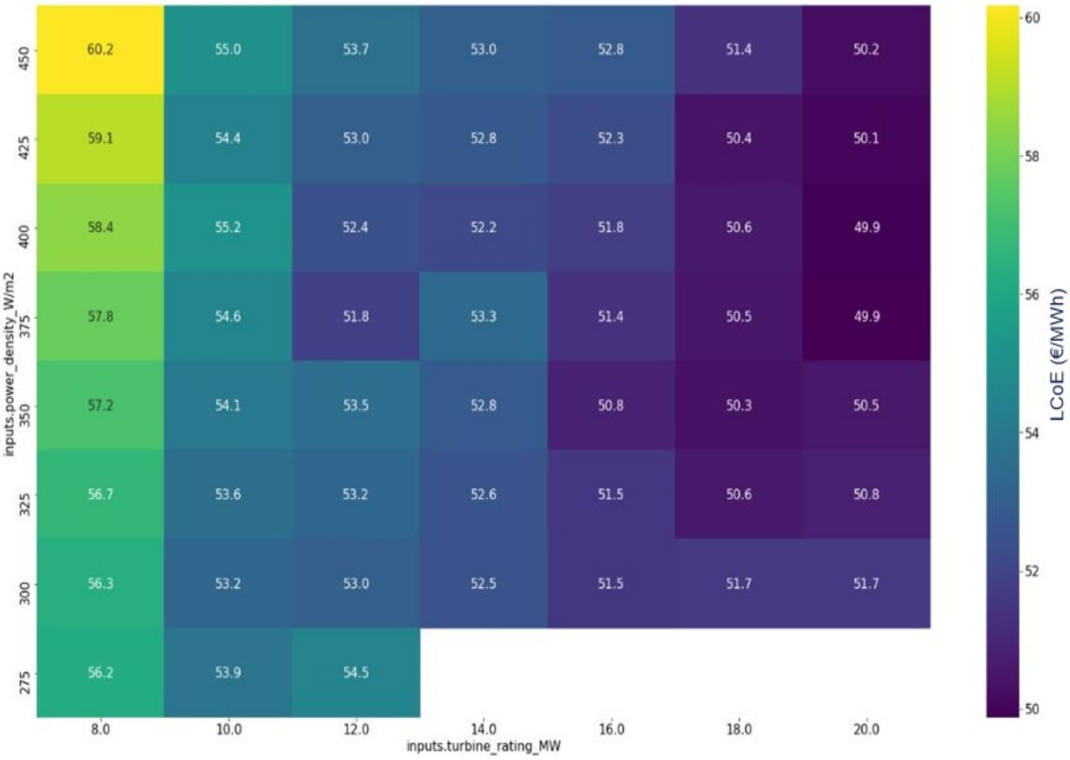


Figure 5-4 LCoE heatmap with turbine rating and power density & LCoE

Considering the expected availability of turbine sizes in the medium term (~2030), DNV has chosen a 20 MW turbine model, with a rotor diameter of 265 m (362 W/m2) and a hub height of 155 for concept design.

4.3 Foundation

Foundations were modelled for each site, using the assumed turbine of 20 MW generator capacity and 265 m rotor diameter. The model performs an optimisation exercise to iterate through foundation design parameters to identify the lowest-cost solution that satisfies technical requirements. The tool then calculates the mass of the foundation required to meet design standards and then derives total costs using unit costs for primary steel, secondary steel and ancillaries such as anodes and coatings. Indicative soil profiles were developed for each project site (using "average" values as required) and imported into the foundation model; each modelled foundation is therefore specific to the site characteristics. Foundation unit costs are based on information from the supply chain and project data and represent DNV's current best estimate for the offshore wind industry. Transportation costs are explicitly modelled as the transportation requirements between the middle east to India. As there is uncertainty in the exact location of fabrication facilities etc. this is considered reasonable at this stage.

Based on information gathered in the FOWIND study [9], the following "Lower Bound" soil profile has been used for Gujarat. This is an experience-based geotechnical zone description developed by DNV's offshore geotechnical department for the purpose of providing preliminary foundation designs. This is a generic soil profile developed based on a number of data acquired out of knowledge/experience from working offshore in this region for a number of decades.

Table 5-3: Soil Profile for Gujarat

Depth from [m]	Depth to [m]	Soil type	Submerged unit weight [kN/m3]	Shear strength from [kPa]	Shear strength to [kPa]	Epsilon 50 [-]	Friction angle [deg]
0	40	Clay	7.5	5	50	0.01	0
40	100	Sand	10	-	-	-	30

As noted in [9], it should be noted that the estimated soil profiles are considered "weak" when compared with "typical" North Sea conditions. In particular, the clay layer which extends to a significant depth (40m) in the lower bound profile can be described as "very soft". For reference, a key strength parameter for clay soils is the "undrained shear strength" (Su) and in Northern Europe values of 200-400 kPa might be seen versus Gujarat's projected range of 30-50 kPa. The clay layer will provide very limited lateral support to piled foundations. The deeper sand layer would provide more support to piles compared with the weak clay layer, although cannot be considered of high strength.

Based on information gathered in the FOWIND study [10], the following mixed type of soil profile has been used for Tamilnadu. It can be considered as an intermediate soil profile between the lower bound "sand" soil profile and upper bound "cemented" soil profiles considered in the FOWIND report [10]. This is an experience-based geotechnical zone description developed by DNV's offshore geotechnical department for the purpose of providing preliminary foundation designs. This is a generic soil profile developed based on a number of data acquired out of knowledge/experience from working offshore in this region for a number of decades.

Table 5-4: Soil Profile for Tamil Nadu

Depth from [m]	Depth to [m]	Soil type	Submerged unit weight [kN/m3]	Shear strength from [kPa]	Shear strength to [kPa]	Epsilon 50* [-]	Friction angle [deg]
0	3.3	Sand	7	0	0	-	20
3.3	4.6	Clay	7	80	80	0.05	0
4.6	8.7	Clay	8	125	200	0.05	0
8.7	11.6	Sand	8	0	0	-	20
11.6	19.1	Clay	8.5	120	120	0.05	0
19.1	28.3	Sand	8.5	0	0	-	20
28.3	31.1	Sand	8.5	0	0	-	20
31.1	37.4	Sand	8.5	0	0	-	25
37.4	To depth	Sand	8.5	0	0	-	25

*Epsilon 50 (ε-50) is defined as the soil strain at 50% of maximum deviatoric stress.

This soil profile represents a significantly weaker soil profile with loose sand layers and clay layers of low to medium shear strength. These loose sand layers may present problems for lateral and vertical resistance. Of considerable uncertainty at this stage is the spatial distribution of each soil type.

Hence, for both Gujarat and Tamil Nadu, **DNV considers monopiles and jackets as feasible technical options for additional assessment by the foundation contractors in the design phase post-assessment of the geo-tech results**

Whilst indicative soil profiles for each project site were used within the Renewable. Architect foundation model and detailed site investigation would produce more detailed ground condition information to inform the foundation's detailed design. The foundation design model also uses a simplified wave loads model, and turbine loads from the generic modelled turbine, and therefore additional uncertainties are introduced into foundation sizing. Detailed design, using detailed site investigation data and type-specific turbine loads, would be expected to reduce foundation mass (and hence cost) in comparison with the Renewable. Architect results. However, it should be noted that the conservatisms within Renewable. Architects are common to all modelled sites. Renewable. Architect uses each site's average depth for foundation sizing; bathymetric variation across a site is not accounted for, and no clustering of foundations is assumed. Again, both aspects would be considered during detailed design and would be expected to yield benefits in total foundation steel mass.

4.4 Electrical Design

Whilst offshore wind electrical system is very similar to traditional onshore wind electrical systems, subtle differences in the nature of components, their ratings and application make it necessary to become familiar with the base components prior to discussing network topologies.

Offshore wind turbines

The electrical rating and performance of the offshore wind turbines can have a significant impact upon the design of the power evacuation infrastructure. Offshore wind turbines are presently available with options for MV levels of 33kV and 66kV.

In terms of their performance, all currently available offshore wind turbines are of Type 3 (Doubly Fed Induction Generator) or Type 4 (Full Converter) technology. Such technologies utilise power electronics and are capable of meeting modern grid code requirements of fault ride-through and voltage control, thereby helping in maintaining grid stability. The vast majority of offshore wind turbines available today are of the most flexible full converter (type 4) technology.

Submarine array cables

The submarine array cables typically operate at MV levels of 33kV/34.5kV or 66kV and are used to interconnect 'arrays' of wind turbines together to transmit power either directly to the shore or to an offshore substation. The submarine array cables along with export cables (discussed in the later section) constitute more than 50% of the overall CAPEX of the electrical infrastructure.

Array cables are of 3-core design usually extruded insulation of XLPE (cross-linked polyethene) or Ethylene Propylene Rubber (EPR) (shown in Figure 5-5) and are of a wet or semi-wet type, which means that they do not employ an extruded water blocking metallic sheath over the cable rendering them lighter and cheaper than submarine HV cables.

The selection of cable conductor type/size depends upon the most optimal cross-section with regard to load capacity, voltage drop, short-circuit capability and cost/capitalised energy losses over the operational lifetime.

Figure 5-5: (left) Medium-voltage submarine cable, XLPE insulated; (middle) Medium-voltage submarine cable, including fibre optic cable; (right) Medium-voltage submarine cable, EPR insulated [9]

Offshore HVAC Substations (OSS)

The major objective of Offshore High Voltage Alternating Current (HVAC) Substations (shown in Figure 5-7) is to transform the medium voltage used in arrays to a higher voltage for more efficient transmission to the shore. The offshore substation consists of the following major electrical components:

- HV Switchgear (Gas Insulated Technology)
- MV Switchgear (Gas Insulated Technology)
- Auxiliary and backup supply systems
- Protection, control and communication equipment
- Reactive power compensation (optional, depending upon system design) in the form of shunt reactors to compensate the HVAC cable capacitance

The offshore substations are large offshore structures consisting of a supporting sub-structure (i.e., foundation) and topside (i.e., the housing platform), as shown in Figure 5-6. The offshore substation, alongside MV and HV submarine cable, is one of the most significant capital cost items in an offshore wind evacuation system. Globally, a single offshore HVAC substation has been installed in sizes up to approx. 1400MW. The size and number of offshore substations in a single wind farm typically depend upon the overall size of the wind farm, the layout of the wind farm (wind turbine locations), installation challenges and available vessel capacities, distance from the shore, and hence is a matter of a techno-economic analysis to determine the most optimal solution.

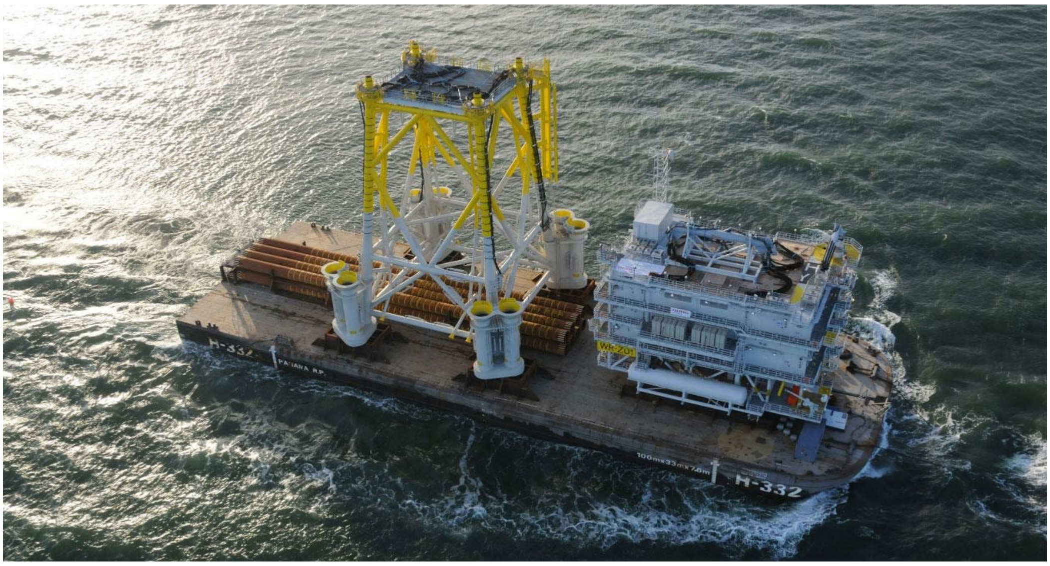


Figure 5-6: Offshore substation top side and sub-structure [10]

Figure 5-7: HVAC transformer platforms for Greater Changhua Offshore Wind Farms [11]

Submarine Export Cables

The submarine export cables connect the offshore HVAC substation to either the onshore electrical infrastructure (typically onshore substation or switchyard) or to the HVDC converter station. Submarine export cables are of 3-core design using extruded XLPE insulation and can transfer 300-400 MW on a single cable circuit practically up to 1600 sq. mm till date. Presently, up to 275kV HVAC cables have been used in offshore installations.

Submarine cables may utilise either copper or aluminum conductors' although copper is more common in offshore installations due to its light weight (compared to the aluminum variant) and low power losses. Offshore cables are buried about 1-3m in the seabed to protect them from damage during operation and careful assessment of the appropriate burial depth is crucial to mitigate in service failure.

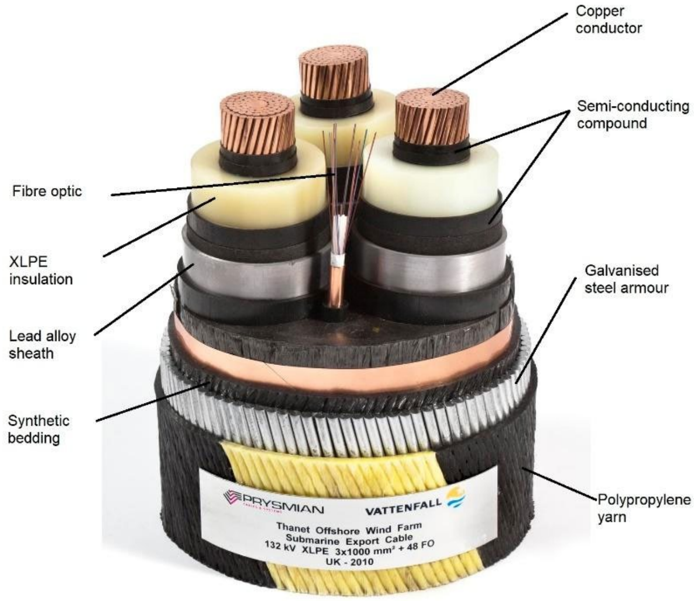


Figure 5-8: An example of a submarine HVAC cable

The submarine cables are designed with integrated optical fibres for communication between the wind turbines, the offshore substation, and the onshore substation. Single-mode fibres are commonly prescribed in a number of 24 – 96 fibres depending on the communication network requirements. One or two fiber steel reinforced and watertight tubes are common. It is advised that the fiber tubes are protected by a semi-conducting PE sheath being earthed in both ends to avoid induced voltages that could damage the PE sheath and HV cable components. Depending on the cable length stainless steel wires (non-magnetic thus having lesser circulating currents can be considered).

The integrated optical fibres can also be utilised for distributed sensing technologies for power cable monitoring. Distributed sensing technology includes distributed temperature sensing, distributed acoustic sensing and to a lesser degree distributed strain monitoring. The Distributed Temperature Sensing in submarine power cables includes:

- Real-time thermal rating of cables (also known as dynamic cable rating)
- Hot spot detection

Distributed Acoustic Sensing is a more recent development with some of the following key applications:

- Asset life monitoring
- Fault detection
- Substation condition monitoring

Landfall & Onshore Cables

When the submarine export cable reaches "the landfall" the submarine cables are joined to an onshore cable at the transition bay. The landfall is a complex marine coordination operation requiring the pull-in of cables from the installation vessel to the onshore transition joint bay. The landfall will often represent a thermally limiting case for the cable system as the burial can be quite deep. It is often practiced to splice a larger diameter cable to the landfall end of the submarine cable in order to mitigate this thermal constraint. Typically, a single core cable is utilised in the onshore installation as it requires less water-blocking measures than submarine cable designs. The onshore cables are laid in trenches (often in ducts) and buried to protect them from external damage. Cross bonding is typically employed to minimise circulating currents in the cable sheaths and increase equivalent rating.

Onshore HVAC Substation/Switchyard

At the onshore HVAC substation/switchyard, the power received from the offshore substation through the offshore/onshore export cables will be transformed to the correct voltage level (in case the grid interconnection voltage level is more than 220kV) for injection into the grid. The main objective of an onshore HVAC substation/switchyard is to house the following components:

- Fixed shunt reactors for compensating the HV cables.
- Power Transformers (in case grid interface voltage level is more than 220kV).
- Protection, control and communication equipment.
- Additional compensating devices such as STATCOM, and SVCs (optional) to meet the grid code requirements.
- Harmonic filters (optional, may be required depending on design) to meet the grid code requirements.
- Control room for entire offshore wind farm and accommodation facilities(optional).

The onshore HVAC substation can be of GIS or AIS technology.

Figure 5-9 *shows the Hornsea 1 onshore HVAC substation capable of evacuating of about 1.2GW power from the Hornsea 1 offshore wind farm. The substation is housing three 400/220kV auto-transformer of 500MVA rating each, three 220kV C-type harmonic filters (band-pass) each rated 100MVAr, three STATCOMs each rated ±200MVAr, two 400kV C-type harmonic filters (high-pass) with each rated 75MVAr and several shunt reactors both on 220kV and 400kV buses.*

Figure 5-9: Hornsea 1 onshore HVAC Substation [12]

66 kV array voltage is considered suitable for both Gujarat and Tamil Nadu. One offshore substation was considered, for both Gujarat and Tamil Nadu, to step up the voltage from 66 kV to 220 kV. 220 kV offshore export cable (630 sq. mm. XLPE Subsea cable) was identified as suitable to be connected to an onshore 220 kV (or 230 kV) switchyard, followed by 220 kV (or 230 kV) onshore overhead line to the electrolysis facility.

For the purpose of electrical concept design the following configuration in **Figure 5-10** has been considered 50 number of WTGs of capacity 20 MW each. The offshore wind farm capacity of the wind farm is therefore 1000 MW. Based on the conclusions of the initial conceptual investigation 66 kV array cables have been considered for interconnecting the 20 MW turbines. The offshore wind farm location in Gujarat is within Zone B (subzone B1) which is around 38 km away from the shore. Similarly, the offshore wind farm location in Tamil Nadu is within Zone B (subzone B1) which is around 15 km from the shore.

Figure 5-10: Layout of WTGs of 1GW OWF in Tamil Nadu (left) and Gujarat (Right)

The electrical BoP network (of Array cables, Offshore substation and export cable) is considered as below in the study:

State	Cable Type	Approx. Length (km)
Gujarat 1GW OWF	**Export Cable :** 220kV, 3 circuits of 3-core 800 sq. mm XLPE Cu Copper Cables	38
	Offshore Substation: 220/66kV with 2x500MVA Power Transformers	
	Array Cable : 66kV, 3-core 185sqmm Cu cable	Aggregated length of 112KM
Tamil Nadu 1GW OWF	Export Cable :230kV, 3 circuits of 3-core 800 sq. mm XLPE Cu Copper Cables	15
	Offshore Substation: 230/66kV with 2x500MVA Power Transformers	
	Array Cable : 66kV, 3-core 185sqmm Cu cable	Aggregated length of 113 KM

4.5 Electricity Generation Estimate

DNV has done the wind climate and energy production assessment for selected sites in Gujarat and Tamil Nadu as described in the following sections. The following sections present a description of the layout optimization, Project site and turbine technology. It then describes the available measurements and analysis of the wind data followed by an evaluation of the expected gross and net energy, as influenced by assumed losses.

4.5.1 Energy Production Assessment Methodology

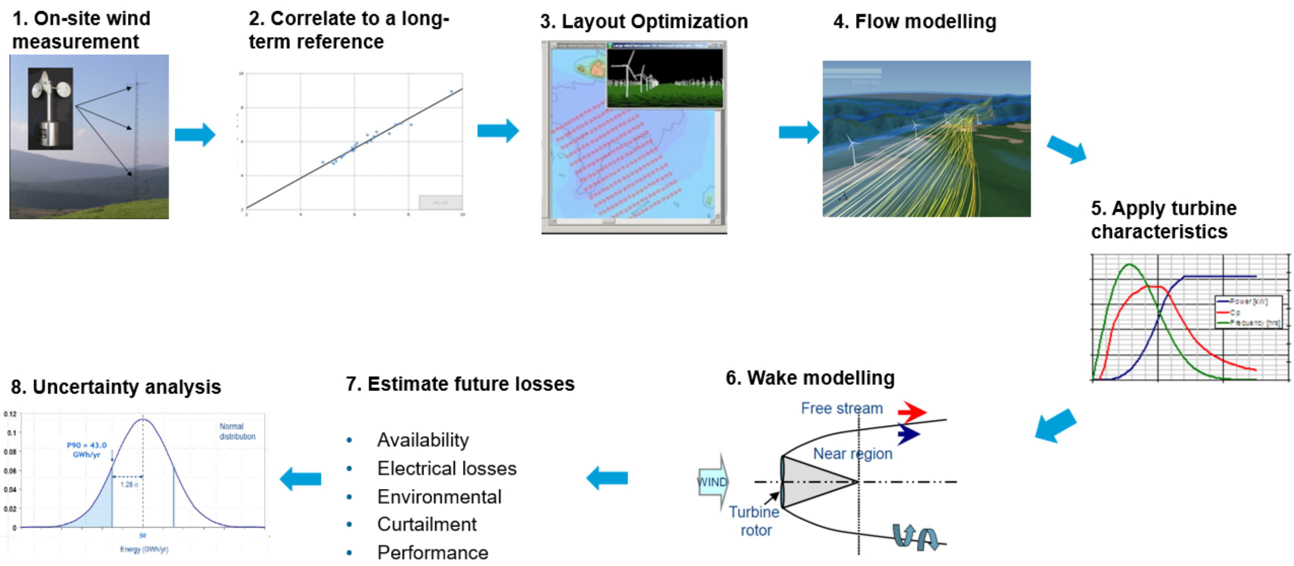


Figure 5-11 Workflow of Energy Production Assessment

Figure 5-11 depicts the general workflow of energy production assessment. The following steps have been undertaken to estimate the future energy production at the site:

Determination of the Long-Term Wind Speed at the Mast

The wind resource is of paramount importance for the viability of a wind project and DNV has used its own proprietary software WindFarmer Analyst to undertake the following analyses for the site:

- Review and quality checking of measured wind data from the site masts and long-term reference data, including checks for erroneous data and instrument degradation.
- Review of calibration of anemometry (if any masts are available at the site) and RSD Filtration and verification.
- Synthesis of wind data to maximise the data coverage.
- Correlation of on-site data to long-term ground-based reference measurements, if available.
- Correlation of on-site data to the MERRA-2 or ERA-5 or Vortex long-term data set. The MERRA-2 dataset, published by NASA, uses weather measurements from a number of sources as inputs to a numerical atmospheric model in order to produce a description of the historical global state of the atmosphere, including wind speed.
- Adjustment of the measured wind speed to make it representative of the long-term period.

Determination of the Long-Term Wind Speed across the Site

- Correlations will be performed between wind speed data from various monitoring heights, to assess the vertical variation of wind speed on a directional basis.
- These assessments of directional variation of wind speed with height will then be used to estimate the wind speed at the hub heights of the turbines at the mast locations.
- The WAsP wind flow model, which is the industry standard tool, will be used to predict the horizontal variation in wind speed across the site at hub height.

- The model will incorporate elevation and surface roughness information. Surface roughness information will be digitised from publicly available satellite images and/or observations taken during any visits to the site by DNV engineers.
- If there are multiple masts at the site, the wind speed predicted from the WAsP model initiated from the most representative mast will be used to predict wind speeds in different areas of the site; and
- Where deemed necessary, adjustments will be made to the wind speeds predicted by WAsP to account for known weaknesses in the WAsP wind flow model.

Determination of the Long-Term Energy Production of the Wind Farm

- Wake modelling along with blockage effects to establish array losses, including the impact of any surrounding operational turbines will be carried out using DNV's industry-standard software package WindFarmer Analyst.
- Sources of possible energy production loss will be reviewed and accounted for to the extent possible; and
- A prediction will be made of the expected net annual energy production of the wind farm at the P50 level only.

Wind Farm Layout Optimization

Based on the site boundaries and constraints provided by the Customer and identified by DNV, modelled wind speeds across the site, and agreed wind turbine type, an initial model of the wind farm is developed.

A digital terrain model is derived from public domain elevation data which is suitable for wind mapping purposes. Surface roughness elements are digitised from public domain aerial and satellite images of the area. Combined with modelled wind speed data developed by DNV for the site, this is used to develop an optimised layout for the wind farm using the WindFarmer software package. The layout optimisation aims to place turbines in locations that will maximise the total energy yield while adhering to any constraints on turbine placement, including specified inter-turbine separation.

Power time series analysis

The Power time series (PTS) is using concurrent time series of temperature and pressure, wind speed and wind direction for a minimum period of at least one year of valid data.

Using the power curve for the turbine, and the results of site wind flow modelling and energy assessment, an hourly time series of power output is generated for the Wind Farm. The power production is calculated taking into account turbine wake and hysteresis losses and air density effects.

The resulting power time series is then scaled by [availability, electrical efficiency, turbine performance, environmental, curtailment] loss factors. These loss factor values represent the average over a 20-year period.

4.5.2 Wind Resources Measurement

Wind resources measurement is the process of collecting data on wind speed, direction, and turbulence at a specific location. This data is used to assess the potential for wind energy generation at that location. There are a number of different methods for measuring wind resources. Onshore Meteorological towers are tall structures that are equipped with instruments to measure wind speed, direction are most commonly used.

Floating LiDAR systems (FLS) are becoming increasingly popular for wind resource assessment in offshore wind farms. FLS has the potential to reduce installation costs compared to fixed met masts. However, FLS must be able to withstand the harsh conditions of the open ocean, such as strong winds, waves, and currents. They must also be able to collect accurate and reliable wind data in a variety of weather conditions.

Figure 5-12 Floating Lidar system (FLS) [13]

The Carbon Trust has developed a maturity framework [14] for floating LiDAR systems. The framework defines three stages of maturity:

- Stage 1: Baseline. Systems at this stage have demonstrated the ability to measure wind speed and direction with an accuracy of ±10%.
- Stage 2: Pre-commercial. Systems at this stage have demonstrated the ability to measure wind speed and direction with an accuracy of ±5%. They have also been deployed in a variety of offshore wind farm sites.
- Stage 3: Commercial. Systems at this stage have demonstrated the ability to measure wind speed and direction with an accuracy of ±2%. They are also commercially available and have been deployed in a number of offshore wind farm projects.

The Carbon Trust's maturity framework provides a clear roadmap for the development and commercialization of floating LiDAR systems. It is a valuable tool for developers, suppliers, and investors who are interested in the use of floating LiDAR for offshore wind energy. A few LiDAR buoys such as Fuggro's seawtach, and EOLOS's FLS20 have achieved Stage 3 rating under the Carbon Trust Offshore Wind Accelerator (OWA) Roadmap for the Commercial Acceptance of floating LiDAR technology.

4.5.3 Project Description

The Wind Farms zones are located off the coast of the states of Tamil Nadu and Gujarat, approximately 15 km and 25 km from shore line as shown in Figure 5-13 and Figure 5-14 respectively.

DNV has Optimized the proposed turbine layout, considering 50 proposed wind turbines with a hub height of 155-m as detailed in section 4.3.2.

Table 5-5 Proposed layout

Layout	Rated Power [MW]	Hub height [m]	Number of turbines	Turbine model
Tamil Nadu	1000	155	50	Generic 20MW, RD 265m
Gujarat	1000	155	50	Generic 20MW, RD 265m

Measurements of the wind regime have been made at 1 remote sensing device for Gujarat and Vortex Time series for Tamil Nadu.

Source: Google Earth

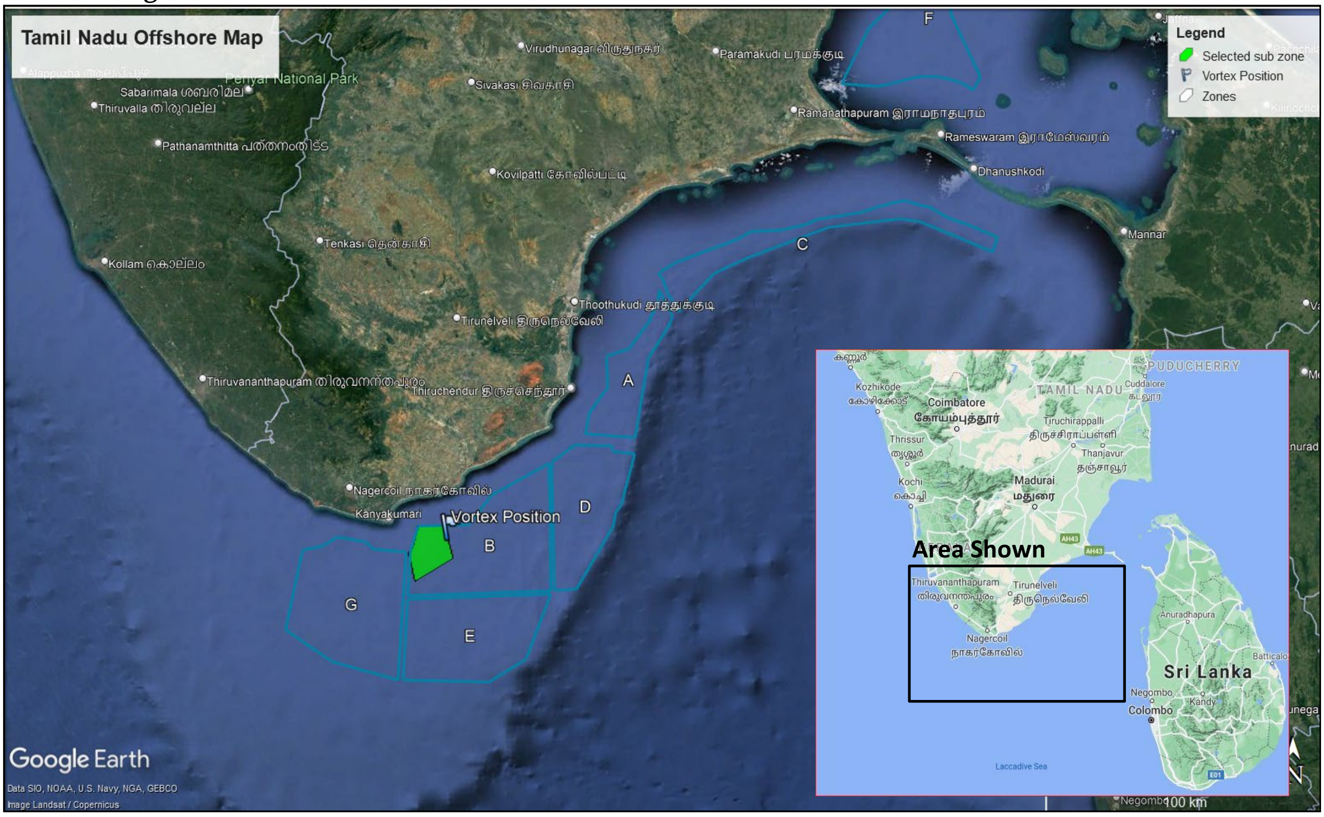


Figure 5-13 Location of the Tamil Nadu Wind Farm

Source: Google Earth

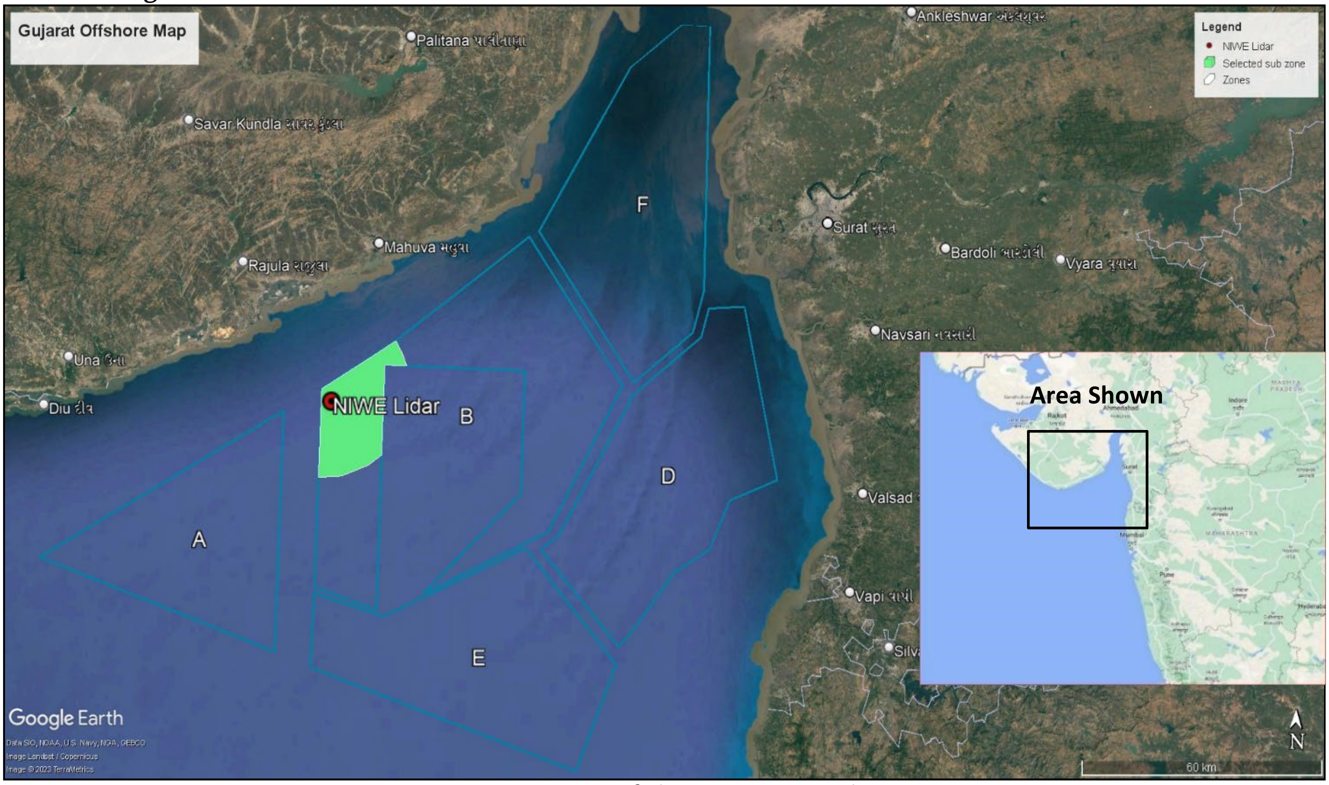


Figure 5-14 Location of the Gujarat Wind Farm

4.5.4 Wind Farm Layout Optimization

In the current assessment, the layout optimization is solely based on maximum energy production. For offshore wind farms, this is mainly achieved by optimally distributing the spacing in between wind turbines within the available area, taking advantage of the wind resource available while minimizing wake losses.

The base layouts within the site boundaries are shown in Figure 5-15 8D×7D rotor-diameters is the spacing used for Tamil Nadu, meaning that perpendicularly to the prevailing wind direction the wind turbines should be spaced by approximately 7 rotor-diameters, and in the prevailing wind direction the distance should be approximately 8 rotor-diameters to minimize the wake loss. Similarly, 16Dx6D rotor-diameters is the spacing used for Gujarat, meaning that perpendicularly to the prevailing wind direction the wind turbines should be spaced by approximately 6 rotor-diameters, and in the prevailing wind direction the distance should be approximately 16 rotor diameters to minimize the wake loss. Furthermore, the layout is diagonal (i.e., in "zig-zag") so that the second-row WTGs are not behind the first-row WTGs, downwind.

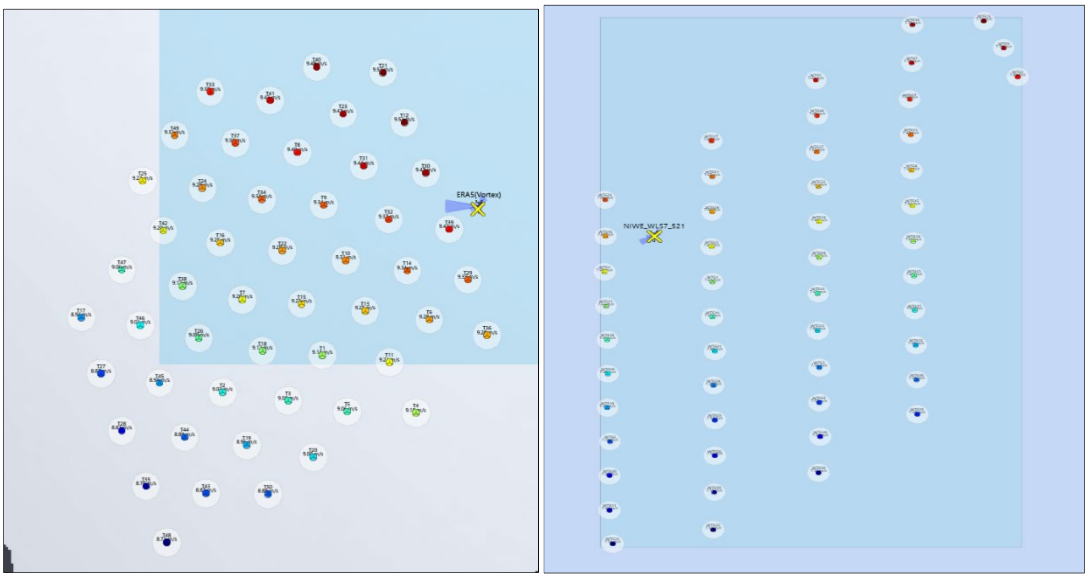


Figure 5-15 Windfarm Layout (50 turbines) with spacing 8D×7D in Tamil Nadu(left) and 16D×6D in Gujarat (right)

(Ellipses represent the spacing envelope around the turbine location having major and minor axis as 8D and 7D and 16D and 6D respectively)

Table 5-6 Layout Optimization for Tamil Nadu

Layout	Spacing	AEP[1](GWh/Annum)	Wake Loss[1] (%)
Base Layout	**8D×7D**	**5370**	**94.8%**
Iteration 1	8D×8D	5370	94.5%
Iteration 2	8D×6D	5380	94.5%

1. The numbers given here are at a high level for the optimization exercise only does not represent the site's actual energy production. Refer to Section 4.3.11 for the actual site-specific energy production.

Table 5-7 Layout Optimization for Gujarat

Layout	Spacing	AEP[1](GWh/Annum)	Wake Loss[1] (%)
Base Layout	**16D×6D**	**3490**	**96.6%**
Iteration 1	14D×6D	3430	94.8%
Iteration 2	10D×6D	3420	94.6%
Iteration 3	8D×8D	3360	93.0%

1. The numbers given here are at a high level for the optimization exercise only does not represent the site's actual energy production. Refer to Section 4.3.11 for the actual site-specific energy production.

The wind farm's internal wake is primarily dependent on the distance between turbines and wind distribution at the site. It is evident from the above tables that, as layout spacing is increased, wake losses are reduced.

DNV concludes the spacing of the base layout (8D×7D and 16D×6D) is thus found to offer a reasonably optimal use of seabed area for maximum energy generation and this would be expected to be subject to more detailed investigations and updates based on detailed project design.

The following constraints have been used for this optimization for Tamil Nadu:

- 7.0 rotor diameter spacing between turbines within each row.
- 8.0 rotor diameter spacing between the rows in the prevailing wind directions.

The following constraints have been used for this optimization for Gujarat:

- 6.0 rotor diameter spacing between turbines within each row.
- 16.0 rotor diameter spacing between the rows in the prevailing wind directions.

4.5.5 On-Site wind monitoring

On-site wind monitoring can be done using various instruments such as Meteorological Masts, LiDAR's and SODAR's. In the current assessment, LiDAR was used as part of the measurement campaign at the Gujarat site. LiDAR works on a similar principle to SONAR but instead of sound, it uses Laser light (also IR or UV) to detect the backscatter from aerosols. The doppler-shift allows LiDAR to detect the wind speed and directions.

A few commonly used LiDAR's in the wind industry are WindCube V1, WindCube V2, WindCube V2 with FCR (Flow Complexity Recognition), and ZephIR 300.

The LiDAR installed in the Gujarat site which is used in this assessment is WindCube V2.

The section below describes the wind data measurements for Tamil Nadu and Gujarat.

4.5.5.1 Tamil Nadu

As no on-site measurement data is available at the Tamil Nadu site. The Wind flow modelling is carried out considering Vortex Series. The Vortex LES© product is a validated model on the WRF model powered by NCAR. The WRF model is downscaled using an algorithm based on the Large Eddy Simulation (LES) approach. The input source of raw reanalysis data is the ERA-5 dataset. The outputs of the model are wind resource 10-minute time series representative of the long-term historical periods in the form of a virtual meteorological mast at several heights. The position for this virtual mast was defined by DNV based on the available area of interest, to select the most representative point for each site.

The characteristics of the Vortex data used are summarized in Table 5-8.

Table 5-8 Summary of Vortex data

Mast	Height [m]	Available period [years]	Valid period [years]	Annual average measured wind speed [m/s]
Vortex (ERA5)	150	20	20	9.5

4.5.5.2 Gujarat

NIWE initiated first of its kind LiDAR-based wind measurement to validate the potential at the preliminary demarcated zones as shown in Figure 5-14. The first site was selected at the Gulf of Khambhat for carrying out the LiDAR-based measurement on a monopile structure. The monopile (platform + substructure) has been installed together with an automatic weather station comprising of an Anemometer, Wind Vane, Temperature, and a pressure sensor at 17 m height from mean sea level in March 2017 and subsequently, the Lidar was installed, and commissioned on 31st October 2017.

WindCube V2 lidar can be programmable for 12 various heights with a minimum height of 40 meters and a maximum height of 200m. The remaining 10-level Heights have been configured towards matching the height of currently available offshore wind turbines in the present market. Prior to the offshore installation, the Lidar instrument was validated against a 120-meter-high met mast for 52 days (22.05.2016 - 13.07.2016) at NIWE's test station at Kayathar, Tamil Nadu.

The characteristics of the measurements made on the site are summarized in Table 5-9.

Table 5-9 Remote sensing campaign summary

Remote sensing device	Period	Measurement heights at MSL[1] [m]
Lidar (WindCube V2)	December 2017 to November 2019	217, 197, 177, 157, 137, 124, 117,104, 97, 87, 77, 57

1. Measurement height is inclusive of lidar platform height of 17-m from mean sea level.

The standard of documentation is good and sufficient to ensure the traceability of the instrumentation throughout the monitoring campaign for the LiDAR NIWE. The data recovery from the LiDAR NIWE instrument seems to be low from November 2017 to January 2018, May 2019 to November 2019 (Between the time duration of 02:00 to 09:00 hours approximately) and no data was recorded from 13th July 2018 to 12th September 2018 due to technical issue, as per NIWE Lidar data analysis report. Wind data coverage is average, with major data loss for the remote sensing device. The monthly wind speed and data coverage results for the masts are provided in **Table 5-10**.

Table 5-10 Summary of remote sensing device data coverage

Remote sensing device	Height [m]	Available period [years]	Valid period [years]	Annual average measured wind speed [m/s]	Wind speed data coverage [%]
Lidar (WindCube V2)	157	2.0	1.5	7.6	72.9

For remote sensing validation purposes, DNV typically recommends that the device is installed near a cup-anemometer mast, at approximately 5 to 10 m for Lidars. NIWE has carried out the validation of the Lidar where DNV was not part of the campaign.

The validation campaign for the WindCube V2 Offshore LiDAR took place at Kayathar, Tirunelveli district, Tamil Nadu, India for a period of 52 days (22.05.2016 - 13.07.2016). The study area was a homogeneous terrain with no obstructions to the wind flow from any direction. The land around the study area was having scattered bushes not more than 1m in height. The Lidar was validated with a 120-m height met mast which was installed 40-m apart in parallel to the metrological met mast of 120-m Height as reported in the NIWE's validation report.

4.5.6 Extension of the site period to the reference period

The inclusion of quality reference data can reduce the uncertainty in the estimate of the long-term wind regime at a site. When selecting appropriate reference data for this purpose the reference wind regime must be driven by similar factors as the site wind regime and the reference data are consistent over the measurement period being considered.

4.5.7 Reference data considered

In India, it is rare to find sources of long-term reference wind data that are suitable for wind energy applications. No measured long-term reference wind data have been supplied and DNV considers it unlikely that a suitable source of ground-based data is available for this region.

However, DNV has considered Modern Era Retrospective-analysis for Research and Applications (MERRA-2) data and ERA-5 data as potential sources of long-term reference data. For this analysis, DNV has obtained hourly averaged wind speed and direction MERRA-2 data at 50 m asl for the period of January 2003 to February 2023, ERA-5 data has been obtained at 100 m asl for the period from January 2003 to January 2023 at the nine nodes closest to the sites.

DNV has therefore considered the index derived from 1 node of MERRA-2 and 1 node of ERA-5 for Gujarat as potential long-term references in the analysis and these have been correlated to the site data as reported in Appendix G

To determine whether the use of the reference data will reduce uncertainty, a correlation was completed of monthly mean wind speeds between each consistent reference source and the site. The results of this analysis are summarized in Table 5-11.

Table 5-11 Summary of correlations to site data

Reference station	Coefficient of determination, R^2 LiDAR NIWE
INDEX	0.98

The resulting estimated long-term measurement height wind speeds at the measurement location are shown in

Table 5-12

Table 5-12 Estimated measurement height long-term wind

Site	Height [m]	Measurement period [years]	Period defining the long-term [years]	Long-term mean wind speed [m/s]	Long-term wind speed adjustment
Gujarat	157	1.5	20.0	7.7	+0.48 %

4.5.8 Hub-height wind speed

To extrapolate the wind speed estimates from the measurement height to the proposed hub height of 155 m, the power law at each measurement site has been evaluated between all relevant measurement heights and applied to the upper-level measurements at LiDAR NIWE in Gujarat and Vortex in Tamil Nadu. The results of this analysis are shown in Table 5-13.

Table 5-13 Shear exponents and hub height wind speeds

Site	Upper measurement height [m]	Upper measurement height wind speed [m/s]	Measured wind shear exponent	Hub-height wind speed estimate [m/s] 155 m HH
Gujarat	157	7.6	0.093	7.6
Tamil Nadu	150	9.5	0.089	9.5

4.5.9 Wind Flow Modelling

Gujarat: The on-site measurement data from Lidar is available for the Gujarat B1 zone which is representative of the site wind conditions. The variation in wind speed over the site was predicted using Lidar data and Vortex FARM© mesoscale model to produce a wind speed map to initiate the flow modelling for estimating the wind resources at turbine locations.

The wind speed map generated for the Gujarat site can be seen in Figure 5-16.

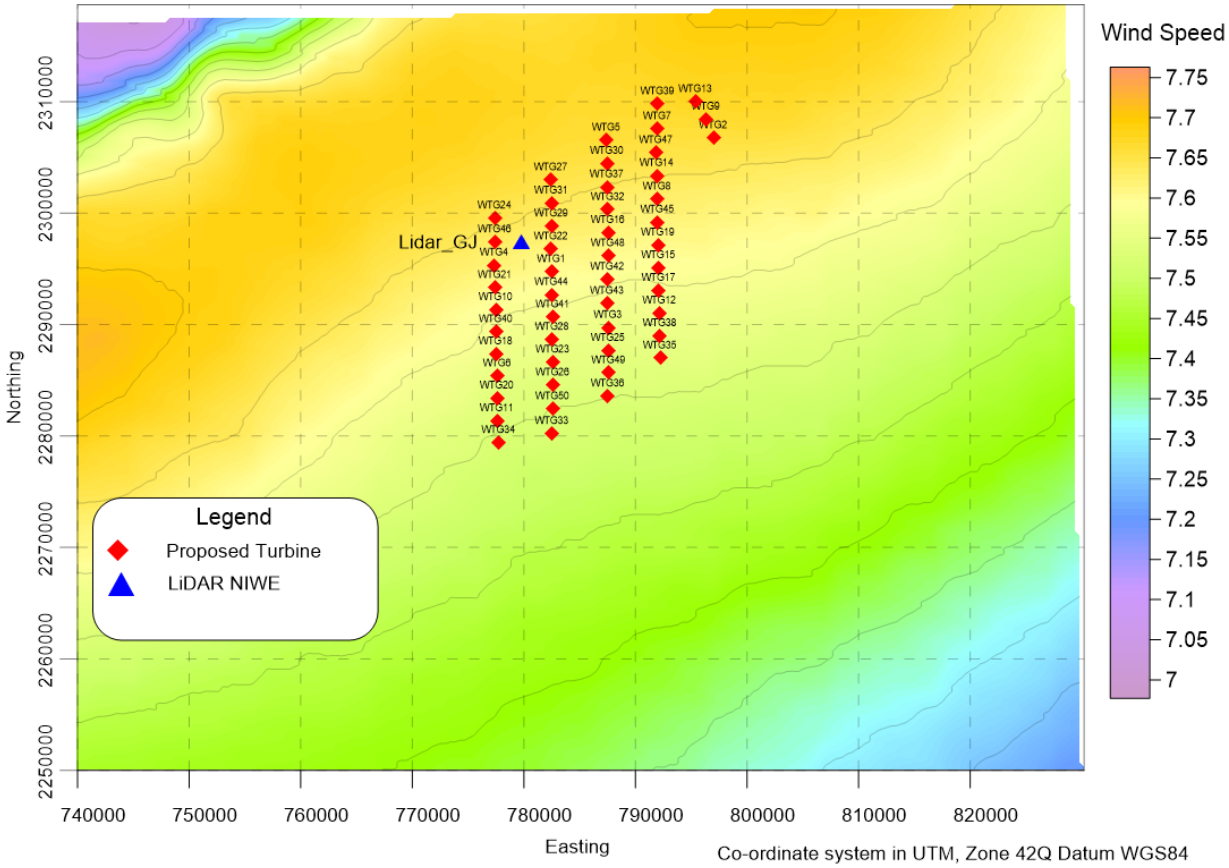


Figure 5-16 Vortex wind map of wind speed results

Tamil Nadu: DNV has used Vortex WRG to access the wind conditions at each turbine location DNV has procured Vortex FARM products for the purpose of carrying out the preliminary studies in the Indian waters. The Vortex FARM product is based on the Weather Research and Forecasting (WRF) model. WRF is a state-of-the-art community model that has been thoroughly documented in open peer-reviewed literature. The WRF model has been employed successfully for a spectrum of applications ranging from operational weather forecasting to climate downscaling. And because WRF is one of the most widely used mesoscale models in the renewable energy industry its performance for wind energy applications is well understood.

Vortex has made use of the European Weather Agency's Era Retrospective Analysis (ERA5) to define the climate inputs into the Vortex model.

The wind map at 150-m resolution sourced from Vortex can be seen in Figure 5-17.

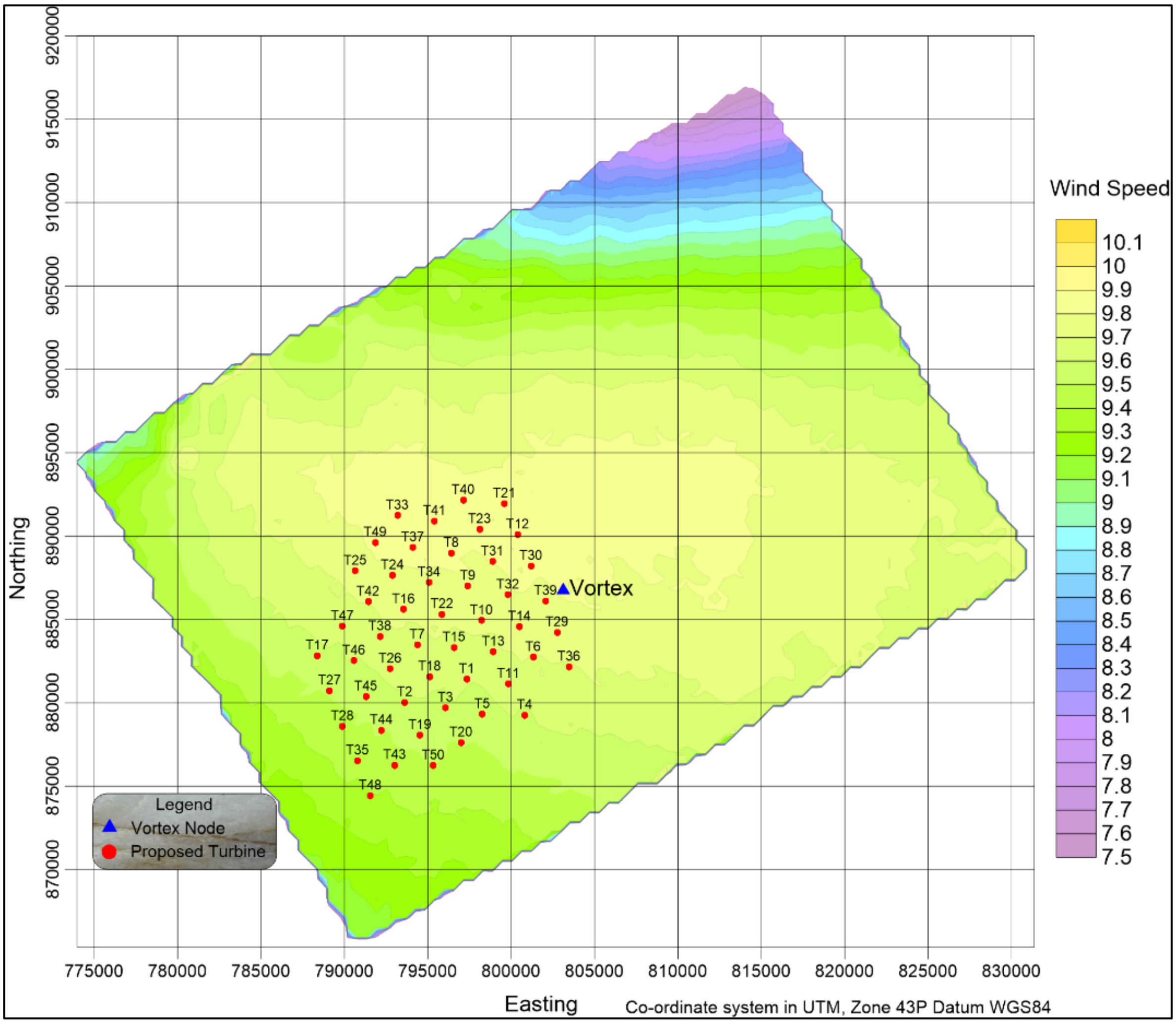


Figure 5-17 Vortex wind map of wind speed results

DNV then made pragmatic adjustments to the long-term wind speed based on the Vortex WRG. DNV strongly recommends revisiting the assessment when on-site measurement data is available for the Tamil Nadu sub-zone B1 as the flow model is solely based on Vortex data sets which may have the following uncertainties. The average long-term hub height wind speed for the wind farm as a whole was found to be 9.2m/s.

Mesoscale weather prediction models are not complete and true representations of the workings of the real atmosphere, owing to science's incomplete knowledge of the myriad of governing physics. Uncertainty also arises because the atmosphere can never be completely or perfectly observed, either in terms of spatial-temporal coverage or accuracy of the measurements. This leads to a variety of unavoidable errors and uncertainties in the modelling process including:

- necessarily imperfect input datasets, based on incomplete measurements.
- numerical approximations used in the dynamical core of the model.
- necessarily imperfect spatial and temporal discretization of the real atmosphere.
- imperfect representation of the various physical processes including, clouds, rainfall, solar radiation, land surface processes, and atmospheric boundary layer processes; and
- inherently limited predictability of the real atmosphere, particularly at the smaller length and time scales.

In addition, DNV has not carried out an independent validation of Vortex's methodology and does not consider it appropriate to formally quantify the uncertainty associated with the results presented here. Due to the uncertainty associated with the modelling process, DNV recommends that the results are used for pre-feasibility purposes only.

While this modeling represents the best possible estimate of the wind resource within the region, it must be stressed that the meso-microscale map is in no way intended to replace measurements. On-site measurements at standard turbine hub heights are essential to any wind energy project development. Also, even though this high-resolution dataset has been created using the latest advances in mesoscale modeling, it does have inherent limitations. DNV recommends revisiting the assessment once on-site measurements are available.

4.5.10 Energy Estimation

The projected net energy production of the wind farm shown in Table 5-14 was calculated by applying a number of energy loss factors to the gross energy production. The predictions represent the estimate of the annual production expected over the first 20 years of operation. Wind farms typically experience some time dependency on availability and other loss factors.

Table 5-14 Energy production summary

		Tamil Nadu	Gujarat		
Wind Farm Rated Power		1000.0	1000.0	MW	
Gross Energy Output		**5034.4**	**3496.3**	GWh/annum	
1	**Turbine interaction effects**	**90.4**	**93.3**	%	
1a	Internal wake effects & and blockage effects	90.4	93.3	%	Project Specific
1b	External wake effect	100.0	100.0	%	Project Specific
1c	Future wake effect	100.0	100.0	%	Not Considered
2	**Availability**	**95.1**	**96.5**	%	
2a	Turbine availability	96.6	98.0	%	Project Specific
2b	Balance of Plant availability	99.5	99.5	%	DNV Standard
2c	Grid availability[2]	99.0	99.0	%	DNV Standard
3	**Electrical efficiency**	**97.5**	**97.5**	%	
3a	Operational electrical efficiency	97.5	97.5	%	DNV Standard
3b	Wind farm consumption	100.0	100.0	%	DNV Standard
4	**Turbine Performance**	**96.3**	**96.3**	%	
4a	Generic power curve adjustment	99.3	99.3	%	DNV Standard
4b	High wind speed hysteresis	100.0	100.0	%	Project Specific
4c	Site-specific power curve adjustment	99.3	99.3	%	Project Specific
4d	Sub-optimal performance	99.0	99.0	%	DNV Standard
4e	Turbine degradation	98.7	98.7	%	DNV Standard
4f	Aerodynamic device degradation	100.0	100.0		DNV Standard
5	**Environmental**	**100.0**	**100.0**	%	
5a	Icing degradation	100.0	100.0	%	Project Specific
5b	Icing shutdown	100.0	100.0	%	Project Specific
5c	Temperature shutdown	100.0	100.0	%	Project Specific
5d	Site Access	100.0	100.0	%	Project Specific
5e	Tree growth	100.0	100.0	%	Project Specific
6	**Curtailments**	**100.0**	**100.0**	%	
6a	Wind sector management	100.0	100.0	%	Not Considered
6b	Grid curtailment	100.0	100.0	%	Not Considered

6c	Noise, visual and environmental curtailment	100.0	100.0	%	Not Considered
	Net Energy Output[1]	**4061.7**	**2951.5**	GWh/annum	
	Net PLF	46.3	33.7	%	

1. Energy figures are derived for a 20-year period, which includes the effect of asymmetric probability distributions.
2. The grid availability is 99% assuming the wind farm going to be connected to a 400kV substation.

Table 5-14 includes potential sources of energy loss that have been either assumed as a DNV standard value or estimated for this project. Project-specific aspects of the loss estimates are provided in the following bullets:

- 1a Internal wake effects & and blockage effects – The wake effects have been calculated using the WindFarmer Analyst wake model. The effect of the blockage has been calculated to understand the changes in the power production at each turbine in the wind farm relative to what it would produce in isolation.
- 1b External Wake Effect - No additional neighbouring wind farms has been included in the assessment.
- 1c Future Wake Effect - No additional future development in the proposed area has been considered for this analysis.
- 2a Availability – DNV has assumed 96.6% turbine availability for Tamil Nadu and 98.0% turbine availability for Gujarat for 20 years of project life based on our past experiences in the Asian offshore market.
- 3a Operational electrical efficiency – Details of the specific balance of plant infrastructure and grid connection point have not been considered and therefore an assumption has been included in accordance with DNV's standard method.
- 4b High wind speed hysteresis - For the Generic 20MW, RD 256-m turbine, the loss has been derived by reducing the cut-out wind speed from 25 m/s to 22.5 m/s.
- 4c Site-specific power curve adjustment – The impact of site-specific conditions such as turbulence and wind shear on turbine performance has been estimated.
- 5c – Temperature shutdown – As the turbine model is the generic theoretical model used for the assessment, it is not possible to estimate the high-temperature de-rating loss at this stage.

It should be noted that the numbers reported in Table 5-14 only provide an indicative estimate of the annual energy production of the wind farm. The estimated P50 annual energy production is subject to uncertainty due to the generic theoretical turbine model considered. It is advised that the customer consider these loss factors and the uncertainty associated with the wind analysis in detail design. LCoE estimation in section 6 is based on net P50 energy derived from this assessment.

4.5.11 Monthly and hourly net energy production

A simulated time series of production data was generated using the time series of air density, wind direction, and wind speed and the WindFarmer energy model developed for the Project. The resulting expected seasonal and hourly variation in energy production at 110 m is presented in Table 5-15 and Table 5-16 in the form of a 12-month by 24-hour (12 x 24) matrix.

Table 5-15 Relative hourly and monthly energy production for Tamil Nadu (Vortex time series)

Hour/Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
0	14.63	11.23	5.78	7.12	16.19	20.22	21.03	20.35	17.11	10.97	8.46	12.83	165.91
1	14.38	10.96	5.6	6.82	15.65	19.99	20.66	20.59	17.06	10.89	8.38	12.68	163.67
2	14.16	10.74	5.63	6.61	14.98	19.6	20.42	20.61	16.98	10.79	8.18	12.58	161.28
3	13.8	10.45	5.6	6.2	14.1	19.01	20.17	20.14	16.75	10.6	7.83	12.17	156.83
4	13.4	10.03	5.43	5.7	13.15	18.2	19.65	19.42	16.32	10.36	7.57	11.73	150.96
5	13.61	9.85	5.2	5.2	12.28	17.46	18.98	19.01	15.94	10.01	7.54	11.74	146.81
6	14.43	10.13	5.17	4.81	11.49	16.76	18.03	18.58	15.49	9.54	7.73	12.15	144.3
7	15.33	10.63	5.27	4.43	11.01	16.44	17.3	18.15	15.04	9.03	8.06	12.7	143.4
8	15.76	10.91	5.3	4.05	10.98	16.88	17.39	18.1	14.75	8.51	8.28	13.03	143.93
9	15.81	11.01	5.27	3.85	11.53	17.91	18.3	18.77	15.06	8.09	8.4	13.28	147.27
10	15.77	11.16	5.39	4.11	12.84	19.51	19.81	20	16.17	8.23	8.6	13.51	155.1
11	15.46	11.11	5.47	4.76	14.71	21.28	21.59	21.4	17.52	8.92	8.74	13.47	164.42
12	14.96	11.09	5.78	5.83	16.84	22.81	23.41	22.73	18.73	9.99	8.77	13.17	174.09
13	14.71	11.31	6.38	7.18	18.89	23.96	24.89	23.87	19.65	11.08	8.78	12.91	183.63
14	14.8	11.63	7.05	8.38	20.23	24.48	25.58	24.61	20.21	11.9	8.66	12.65	190.19
15	15.08	12.04	7.56	9.13	20.8	24.75	25.8	24.91	20.41	12.38	8.33	12.41	193.59
16	15.59	12.58	7.84	9.31	20.74	24.85	25.85	24.78	20.34	12.71	8.11	12.4	195.08
17	16.03	13.07	7.84	9.16	20.51	24.8	25.86	24.43	20.15	12.9	8.07	12.44	195.25
18	16.18	13.31	7.61	8.97	20.14	24.37	25.55	23.81	19.71	12.82	8.15	12.5	193.13
19	16.06	13.23	7.29	8.74	19.51	23.52	24.87	23.15	19.23	12.58	8.33	12.72	189.23
20	15.76	12.82	6.95	8.48	18.71	22.52	24.06	22.44	18.68	12.16	8.58	13.08	184.26
21	15.44	12.26	6.63	8.19	17.93	21.62	23.08	21.43	17.9	11.65	8.8	13.4	178.32
22	15.1	11.73	6.36	7.91	17.22	20.96	22.27	20.51	17.11	11.19	8.8	13.47	172.63
23	14.78	11.35	6.1	7.59	16.62	20.5	21.64	20.11	16.86	11.01	8.64	13.2	168.39
Total	361.01	274.62	148.5	162.52	387.08	502.41	526.21	511.88	423.19	258.29	199.78	306.2	4061.7

Table 5-16 Hourly and monthly energy production for Gujarat (Lidar)

Hour/	Energy Production [a] [Gwh]												
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
0	10.78	8.67	11.05	13.4	15.25	14.76	16.47	13.94	8.13	5.67	8	11.25	137.37
1	11.93	9.46	11.45	12.33	13.69	13.99	16.18	13.95	8.12	5.87	8.24	11.63	136.84
2	12.91	10.06	12	11.58	12.3	12.96	16.01	13.84	7.91	5.9	7.86	11.81	135.14
3	13.67	10.81	12.35	9.96	10.59	11.92	15.88	13.65	7.76	5.94	7.66	12.1	132.29
4	14.17	10.92	12.21	8.05	8.79	11.09	15.74	13.48	7.68	6.36	8.26	12.68	129.43
5	14.54	11.05	12.23	7.11	7.58	10.53	15.19	13.06	7.79	6.83	8.36	12.75	127.02
6	14.88	11.33	11.72	6.36	6.28	9.63	14.31	12.39	7.62	6.8	8.5	12.83	122.65
7	14.74	11.4	10.11	5.11	5	8.79	13.72	11.95	7.06	6.04	8.07	12.3	114.29
8	13.3	10.83	8.1	3.68	4.07	8.55	14.15	12.53	6.43	5.47	7.36	11.02	105.49
9	11.31	9.98	6.55	2.69	3.68	8.46	15.14	13.78	6.49	5.09	6.88	10.15	100.2
10	9.58	8.37	5	2.22	4.26	9.31	15.94	14.24	6.55	4.68	6.2	9.1	95.45
11	7.94	6.54	4.23	2.61	5.63	10.89	16.74	14.53	6.64	4.3	5.47	7.91	93.43
12	6.59	5.21	3.77	3.65	8.05	12.82	17.49	15.11	7.13	4.03	4.76	6.79	95.4
13	5.43	4.48	3.74	5.41	11.58	15.54	18.9	16.21	7.91	3.53	3.93	5.92	102.58
14	4.39	4.03	4.11	7.6	15.01	18.06	20.3	17.4	8.9	3.12	3.21	5.34	111.47
15	3.69	3.9	4.45	9.34	17.3	19.5	21.1	18.32	9.83	2.94	2.79	4.93	118.09
16	3.37	4.04	4.84	11.3	19.47	20.34	21.42	18.84	10.52	3.08	2.82	4.67	124.71
17	3.7	4.35	5.4	13.3	21.38	20.81	21.18	18.63	10.8	3.24	3.09	4.71	130.59
18	4.29	4.75	6.68	15.53	22.79	20.95	20.51	17.7	10.69	3.65	3.74	4.98	136.26
19	4.96	5.05	8.05	17.1	23.2	20.94	19.87	16.76	10.51	4.1	4.59	5.75	140.88
20	5.16	5.01	9.29	17.78	22.57	20.07	18.88	15.78	10.14	4.66	5.38	6.54	141.26
21	6.59	6	10.28	17.93	21.57	18.3	17.63	14.75	9.68	5.5	6.25	7.67	142.15
22	8.16	7.18	10.86	17	19.52	16.36	16.73	14.06	9	5.9	7.01	8.91	140.69
23	9.37	7.64	10.85	15.45	17.41	15.23	16.29	13.71	8.35	5.91	7.53	10.1	137.84
Total	215.45	181.06	199.32	236.49	316.97	349.8	415.77	358.61	201.64	118.61	145.96	211.84	2951.53

5 COST MODELLING

5.1.1 The assumption for offshore wind farm

S.No.	Parameter	Assumption for Tamil Nadu and Gujarat	Remarks
1	Wind farm capacity	1 GW	Based on ToR
2	Design life	25 years	As per typical global practices. This is subject to revision based on site-specific assessment during the project development stage.
3	Turbine Model	20 MW, Rotor Diameter:265 m, Hub Height: 155m	The turbines are assumed to be imported from Europe. The installation of the turbines is done using jack-up vessels transported from Europe.
4	Foundation	Jackets	The jackets are assumed to be imported from the Middle East/ the monopiles from Europe The installation vessels are mobilised from Europe.
5	Internal array cabling	66 kV cables	The inter-array cabling is assumed to be imported from Europe with cable-laying vessels brought from there.
6	Offshore sub-station	One 1 GW offshore sub-station (66/220 kV)	Based on the discussion of the various options for transferring the power collected by the array cables to the onshore grid substation.
7	Export cable	220 kV cabling from the offshore sub-station to the onshore electrical infrastructure	The export cabling is assumed to be imported from Europe with cable laying vessels also from there.
8	Onshore electrical infrastructure	A 220 kV switchyard is considered near the shore followed by 220 kV over-headlines to connect to the nearest grid sub-station	Based on typical onshore wind industry practices in India. The onshore electrical infrastructure is assumed to be supplied from India.
9	Capacity factor/Plant load factor	**Tamil Nadu** 46.3% (1000 MW) with 20 MW 265 m RD model (50 turbines) **Gujarat** 33.7% (1000 MW) with 20 MW 265 m RD model (50 turbines)	Refer to Section 5.5 for the energy assessment.

10	Project development	Project development is considered to include surveys, package management and project execution management	The cost of project development is considered as a certain % of CAPEX based on DNV's global experience. Considering that this is a pre-feasibility study, a % of the CAPEX approach to project development costs is reasonable. For surveys, indicative costing is considered. For a pilot project in a new market, a significant level of additional planning is deemed required from the Developer and the equipment supplier. In addition to the cost associated with planning, there is also a one-time cost to set up offices to house staff. Such additional costs are expected to be considered as overheads and not counted as project costs.
12	Operations and maintenance	Suitable crew transfer vessels are planned to be used to service the wind farm with the support of crane barges for large component replacements.	There are two options for O&M – crew transfer vessels and service operation vessels. Crew transfer vessels are typical considerations for smaller wind farms and new markets. For major component replacements, it is expected that a suitable dedicated jack-up vessel would be mobilised from the middle east when required for major component replacement.
13	Decommissioning	The offshore wind farm infrastructure is considered to be decommissioned after 25 years of operation.	Typical decommissioning costs seen in the European market are considered.
14	Weighted-average-cost-of-capital (WACC)	10%	This is a typical assumption for developing markets like India.
15	Duties and taxes	Not Considered	-

Scope Boundaries

Based on the offshore strategy paper, evacuation of power from the offshore pooling delivery point to the onshore meeting/interconnection point shall be the responsibility of PGCIL (Central Transmission Utility). However, in the revised draft strategy paper, the responsibility of interconnection until the onshore connection point lies with the Developer. But stakeholders are pushing for the cost of developing evacuation infrastructure to be reimbursed by the Government as a way of major incentive for this new sector.

DNV has considered the 2 scenarios as shown in Figure 6-1 for the modeling purpose. In Scenario 1, Developer's responsibility is to offshore substation whereas in scenario 2 developer's responsibility is till onshore grid integration.

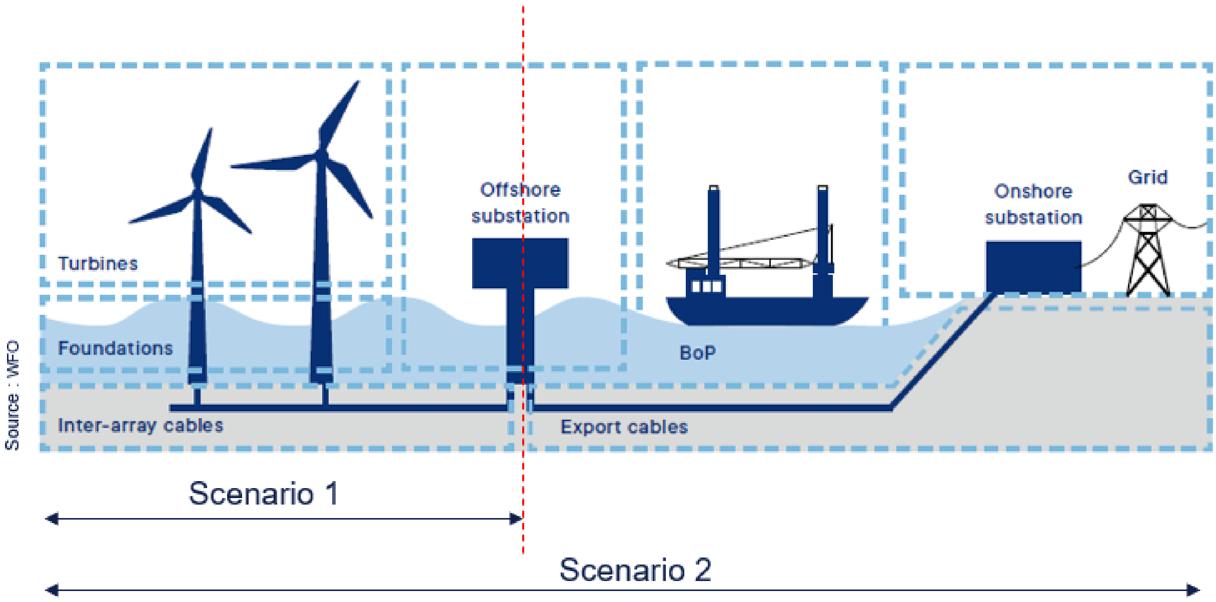


Figure 6-1 Export Infrastructure responsibility scenario [15]

5.2 Set-up of case studies

In the Tamil Nadu and Gujarat case studies in this chapter, the three offshore hydrogen production topologies in chapter 3 are compared (denoted by numbers 1 – 3) for the Tamil Nadu and Gujarat 1 GW wind farms. Furthermore, both PEM and Pressurized Alkaline technologies are analysed (denoted by the letter P/A). The tables below show some key characteristics of the analysed value chains.

Table 6-1 - Description of cases analysed in the Tamil Nadu study

Case ID	Topology	Export infrastructure	Turbine rating	ELX rating	ELX type
TN-1P	Onshore Centralized	HVAC (1x2 substations, 3 cables)	50 x 20 MW	20 x 50 MW (1 plant)	PEM
TN-1A	Onshore Centralized	HVAC (1x2 substations, 3 cables)	50 x 20 MW	20 x 50 MW (1 plant)	ALK
TN-2P	Offshore Centralized	H2 pipeline (10.8")	50 x 20 MW	20 x 50 MW (2 plants)	PEM
TN-2A	Offshore Centralized	H2 pipeline (10.8")	50 x 20 MW	20 x 50 MW (2 plants)	ALK
TN-3P	Offshore Decentralized	H2 pipeline (10.8")	50 x 20 MW	50 x 20 MW (50 plants)	PEM
TN-3A	Offshore Decentralized	H2 pipeline (10.8")	50 x 20 MW	50 x 20 MW (50 plants)	ALK

Table 6-2 - Description of cases analysed in the Gujarat study

Case ID	Topology	Export infrastructure	Turbine rating	ELX rating	ELX type
GJ-1P	Onshore Centralized	HVAC (1x2 substations, 3 cables)	50 x 20 MW	20 x 50 MW (1 plant)	PEM
GJ-1A	Onshore Centralized	HVAC (1x2 substations, 3 cables)	50 x 20 MW	20 x 50 MW (1 plant)	ALK
GJ-2P	Offshore Centralized	H2 pipeline (10.8")	50 x 20 MW	20 x 50 MW (2 plants)	PEM
GJ-2A	Offshore Centralized	H2 pipeline (10.8")	50 x 20 MW	20 x 50 MW (2 plants)	ALK
GJ-3P	Offshore Decentralized	H2 pipeline (10.8")	50 x 20 MW	50 x 20 MW (50 plants)	PEM
GJ-3A	Offshore Decentralized	H2 pipeline (10.8")	50 x 20 MW	50 x 20 MW (50 plants)	ALK

The above scenarios form the basis of a high-level assessment to compare basic types of hydrogen value chains. The onshore centralized scenarios are assumed to exist in isolation from the mainland electrical grid. However, further analysis (beyond the scope of this study) may also consider a grid-connected scenario, where import and export of power from the grid, or supplementation with a behind-the-meter solar farm, can be used to complement offshore wind power. The grid connectivity dynamics and evaluation of the feasibility of a grid-connected project are beyond the scope of this study and would also require analysis on an hourly basis across the project lifetime to assess the potential benefits grid connectivity could bring, in conjunction with the additional grid connection costs required.

The grid-connected concept introduces other complexities, such as how to certify (and what scheme will be used) to ensure that hydrogen is made only from 'green' electrons. Furthermore, being grid-connected may subject the hydrogen production plant to more stringent electrical design requirements to comply with the grid operator rules. This can have significant cost implications for the electrolyser power electronics aspects, which can make up around 25% of the overall electrolyser system cost, depending on the technology selected.

The sections below discuss the results of the modelling, which includes Levelized Cost of Hydrogen (LCOH), CAPEX, OPEX, Levelized Cost of Electricity (LCOE), overall value chain efficiency, and average yearly hydrogen yield. Cost figures are given in Euro (€).

In both case studies, the cost figures are broken down on a category level to provide extra detail, as shown in the table below.

Table 6-3 - Categories and components to break down the results

Main Category	Components	Applicable topology
Wind farm	Foundations	All
	Turbines	All
Electrical transmission infrastructure	Array cables	1. Onshore Centralized 2. Offshore Centralized
	Substation offshore	1. Onshore Centralized
	Export cable	1. Onshore Centralized
	Substation onshore	1. Onshore Centralized
	66/33 kV transformer	2. Offshore Centralized
Hydrogen production	Turbine add-on structure	3. Offshore decentralized
	Hydrogen production platform	2. Offshore Centralized
	Electrolyser power supply	All
	Water Treatment & Cooling	All
	Electrolyser Stacks	All
	Electrolyser Balance of Plant	All
	Hydrogen compressors	All
Hydrogen transmission infrastructure	Hydrogen array pipelines	3. Offshore decentralized
	Hydrogen export pipeline offshore	2. Offshore Centralized 3. Offshore Decentralized
	Hydrogen export pipeline onshore	2. Offshore Centralized 3. Offshore Decentralized
Project costs	Project planning & contingency	All
	Transport	All

5.3 Case study – Tamil Nadu

In this case study, the three offshore hydrogen production topologies in Chapter 3 are compared (denoted by numbers 1 – 3) for the Tamil Nadu 1 GW wind farm. Furthermore, both PEM and Pressurized Alkaline technologies are analysed (denoted by the letter P/A). The case study will compare the Levelized Cost of Hydrogen, Capex, Opex, Levelized Cost of Electricity, Transmission infrastructure cost, Value chain efficiency, and Hydrogen yield.

5.3.1 Levelized Cost of Hydrogen

As can be seen in Figure 6-2 below, the centralized production topologies (1 & 2) feature a more attractive LCOH compared to the decentralized production topology (3). Furthermore, it can be observed that Pressurized Alkaline (A) features a more cost-effective profile than PEM (P) for 2030. It should be noted that the offshore production topologies come with relatively large uncertainties with regard to the cost of offshore installation and maintenance, as well as the “marine readiness” of electrolysis equipment in general for 2030.

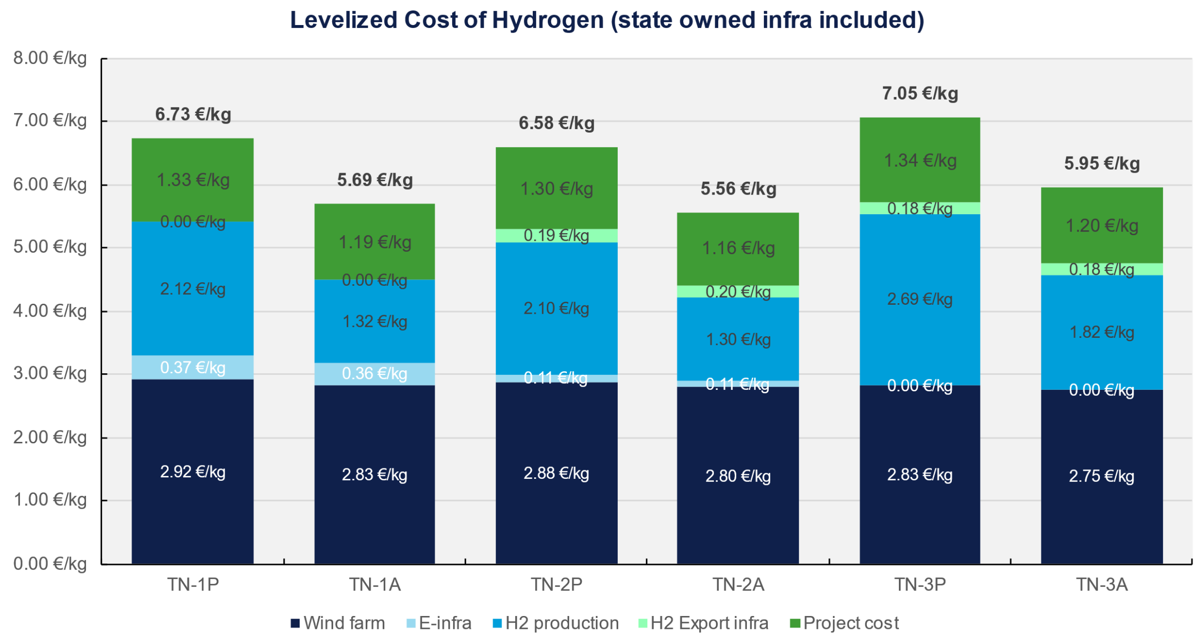


Figure 6-2 Levelized cost of Hydrogen (LCOH) of wind-to-hydrogen value chains for the Tamil Nadu 1 GW wind farm (state-owned infra included)

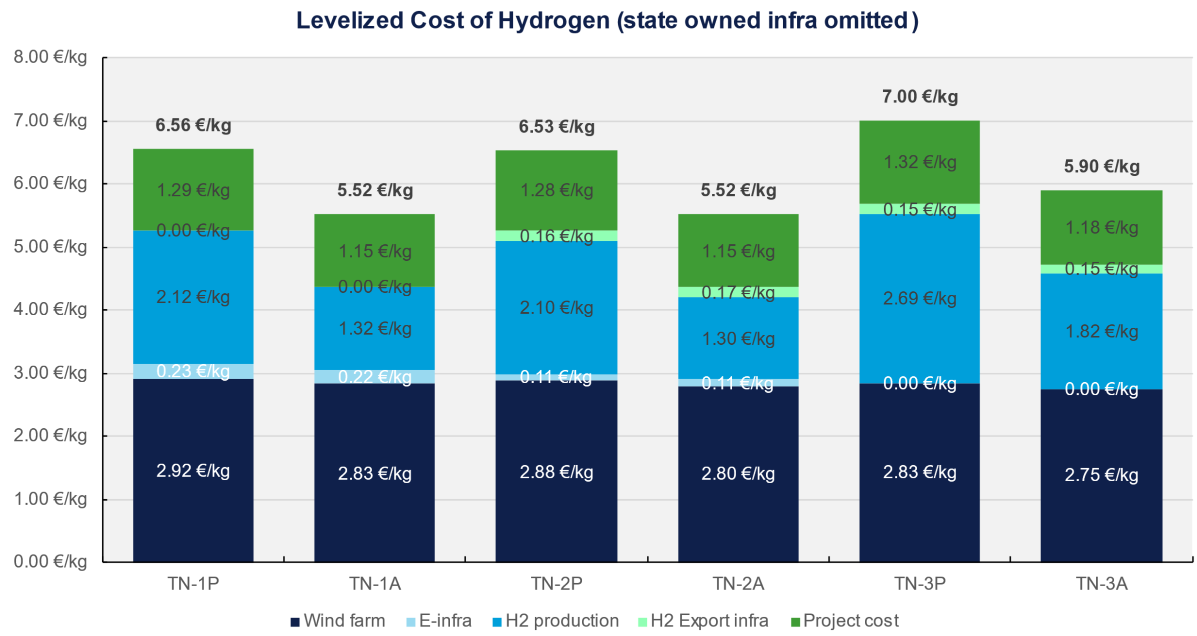


Figure 6-3 Levelized cost of Hydrogen (LCOH) of wind-to-hydrogen value chains for the Tamil Nadu 1 GW wind farm (state-owned infra omitted)

To take a closer look at the most cost-effective option: TN-2A – offshore centralized hydrogen production, using pressurized alkaline electrolysers. Figure 6-4 features a cost split per category and highlights the CAPEX and OPEX share of each category.

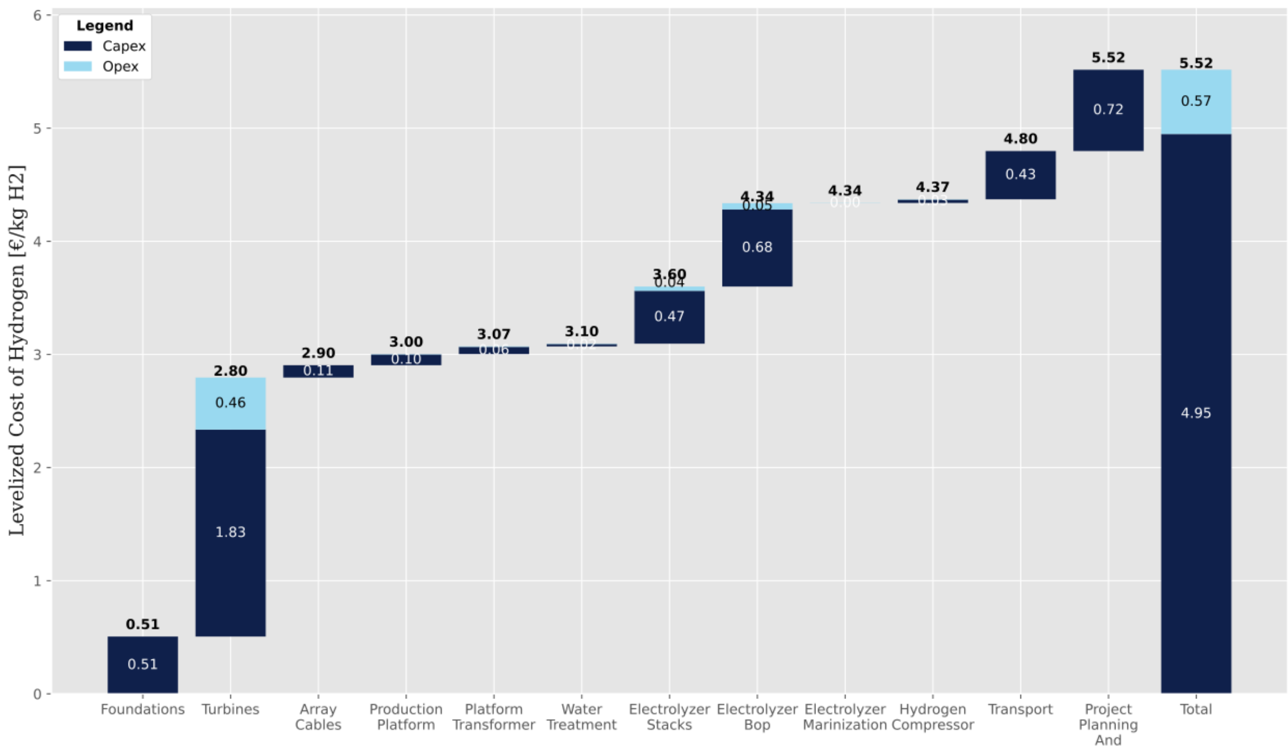


Figure 6-4 Detailed Levelized cost of Hydrogen (LCOH) breakdown for the Tamil Nadu 1 GW wind farm. Case 2A – offshore centralized with pressurized alkaline technology – split between cost categories and CAPEX/OPEX.

5.3.2 CAPEX

As can be seen in Figure 6-5, the main differences between the cases are between the CAPEX of PEM (P) and Pressurized alkaline (A) electrolysers. Furthermore, differences can be observed between the offshore production topologies, generally featuring a higher unit cost and installation cost. It should be noted that the offshore costs for hydrogen production equipment are prone to larger uncertainty.

Upon comparing the CAPEX of the electrical transmission infrastructure with the hydrogen gas transport infrastructure, it becomes evident that hydrogen transport by pipeline is slightly cheaper in terms of transport infrastructure cost, and already at the relatively low distance to the shore of the Tamil Nadu wind farm; this difference is enough to offset the higher costs for offshore production. This is further analysed in section 6.3.5.

Upon omission of the state-owned part of the transport infrastructure (see Figure 6-1), this difference tips in favor of the centralized onshore topology (case 1). This is mainly driven by the relatively large cost of the hydrogen production platforms in case 2.

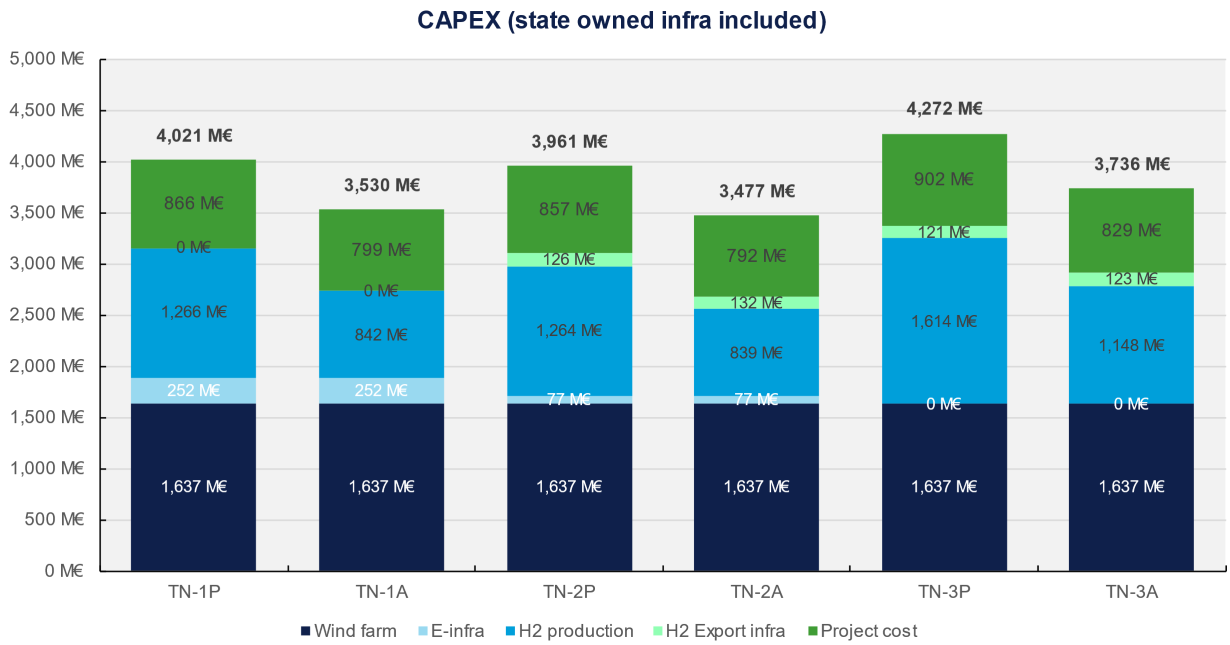


Figure 6-5 – CAPEX (Absolute, 2023) of wind-to-hydrogen value chains for the Tamil Nadu 1GW wind farm (state-owned infra included)

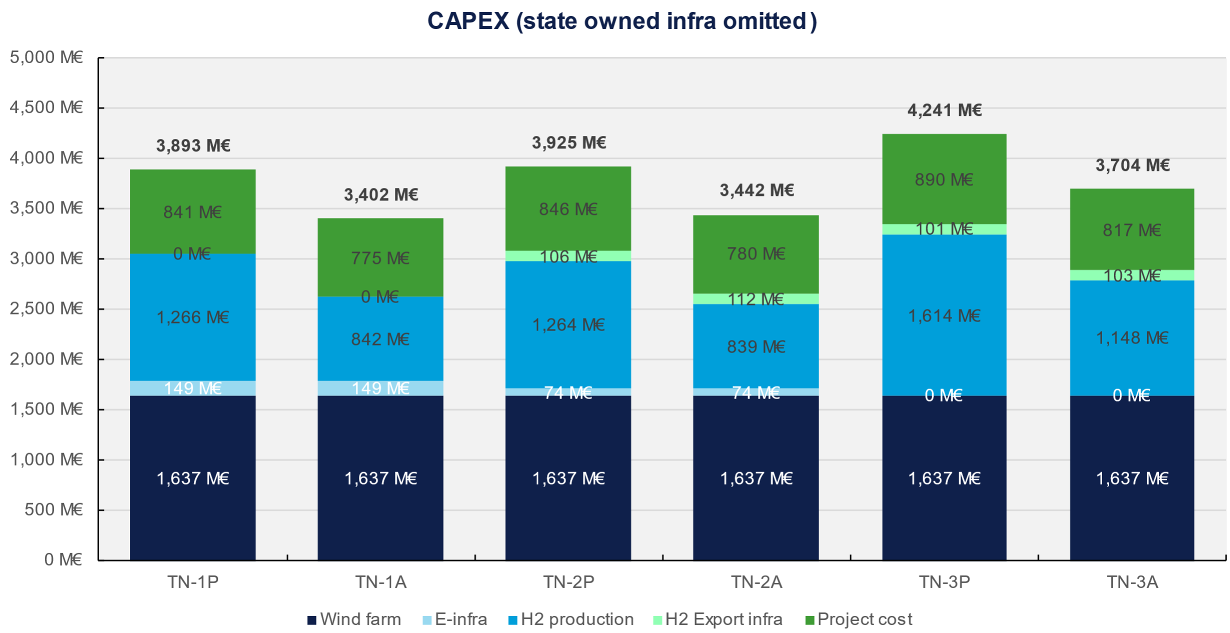


Figure 6-6 – CAPEX (Absolute, 2023) of wind-to-hydrogen value chains for the Tamil Nadu 1GW wind farm (state-owned infra omitted)

5.3.3 OPEX

As can be seen in Figure 6-8 (on the next page), the main differences between the cases are between the OPEX of PEM (P) and Pressurized alkaline (A) electrolysers, this is mainly driven by the cost for stack replacement (at ~5/6 of the project lifetime for Alkaline, at ~3/4 of the project lifetime for PEM). Furthermore, differences can be observed between the offshore production topologies, generally featuring a higher cost for maintenance. It should be noted that the offshore maintenance cost for hydrogen production equipment is prone to large uncertainty. Upon comparing the OPEX of the electrical transmission infrastructure with the hydrogen gas transport infrastructure, it becomes evident that hydrogen transport by pipeline is cheaper.

5.3.4 Levelized Cost of Electricity

An indicative levelized cost of electricity is calculated for all cases. Here it becomes evident that the omission of the high-voltage transmission infrastructure has a significant impact on the LCOE. The Offshore Centralized topology is slightly more expensive than the Offshore Decentralized topology due to the requirement for array cables feeding power from the turbines to the hydrogen production platforms. The omission of the state-owned part of the electrical infrastructure (see Figure 6-1) for the Onshore Centralized case results in a reduction in LCOE of 2.80 €/MWh (4%). In the other cases there is no cost reduction as the export cables and onshore substation are not included in those topologies anyhow.

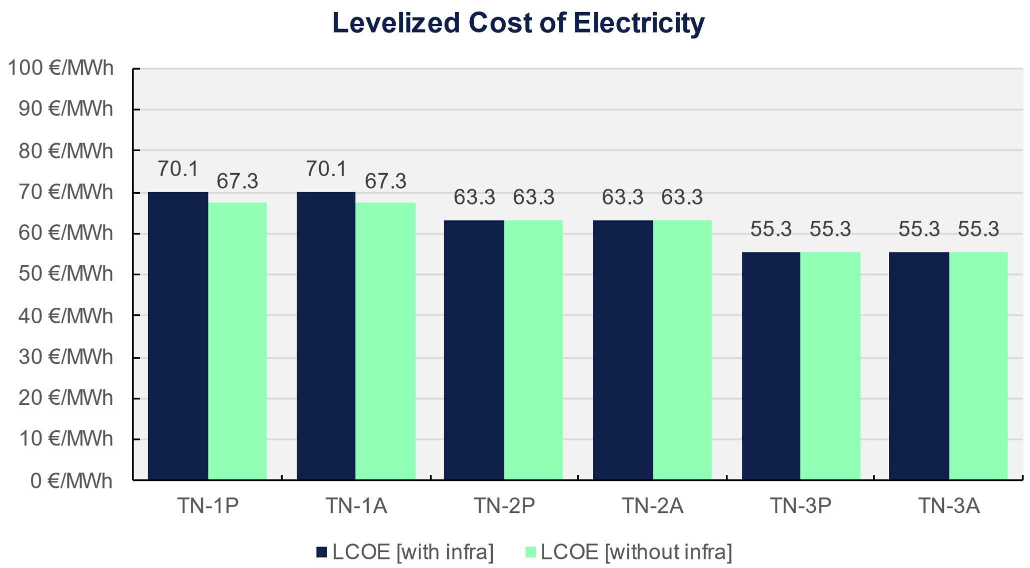


Figure 6-7 Levelized Cost of Electricity (LCOE) of wind-to-hydrogen value chains for Tamil Nadu 1 GW wind farm (with- and without state-owned infrastructure included)

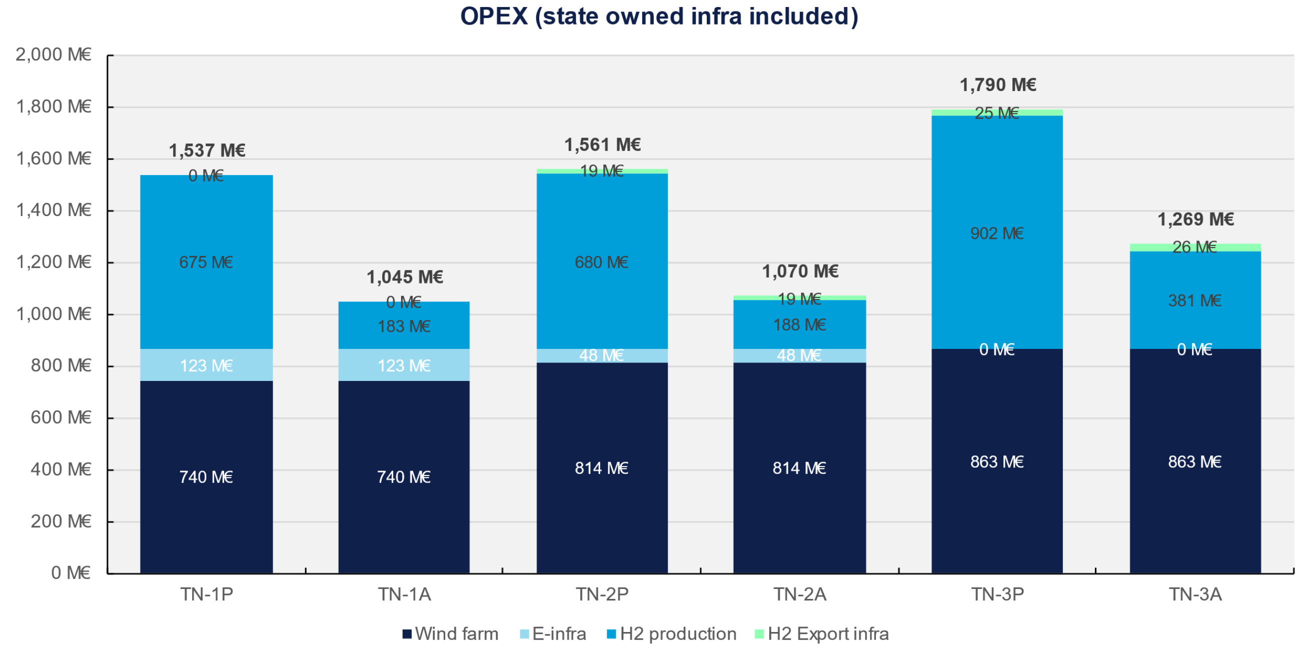


Figure 6-8 – OPEX (Absolute, 2023) of wind-to-hydrogen value chains for Tamil Nadu 1 GW wind farm (state-owned infra included)

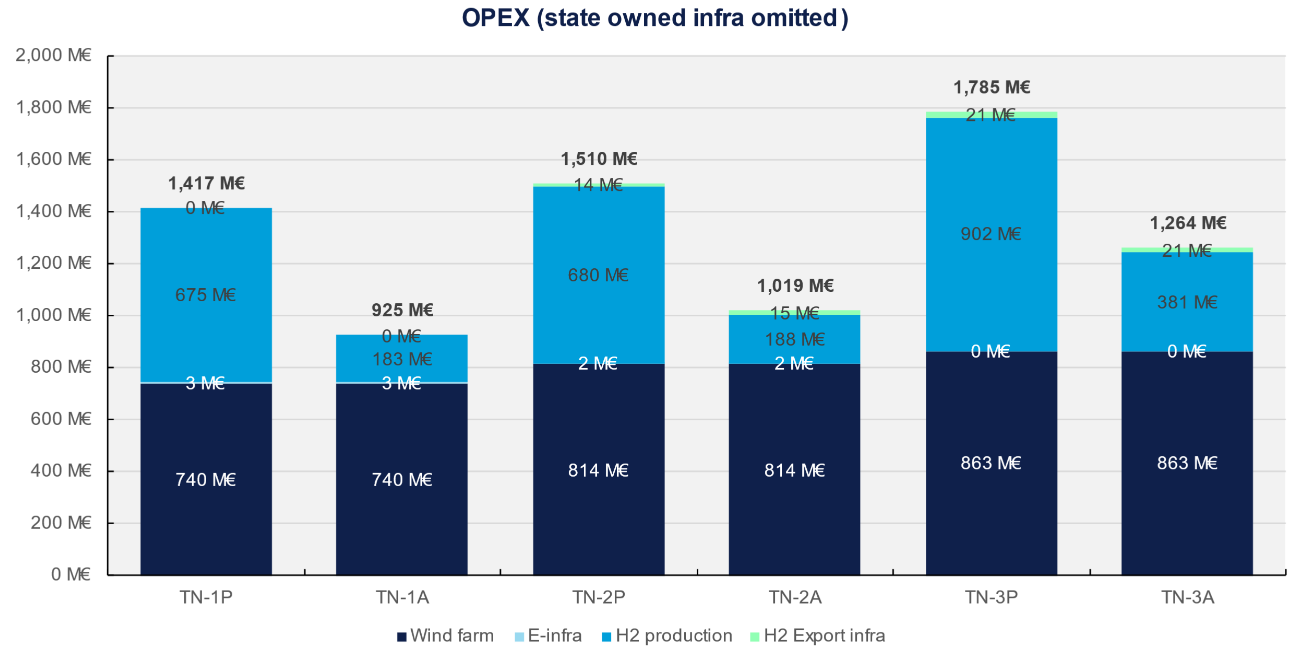


Figure 6-9 – OPEX (Absolute, 2023) of wind-to-hydrogen value chains for Tamil Nadu 1 GW wind farm (state-owned infra omitted)

5.3.5 Transmission infrastructure cost

Upon comparing the total transmission infrastructure cost of the analysed value chains, it becomes evident that the hydrogen transmission options are 15% – 50% cheaper in terms of levelized cost of hydrogen of the transmission infrastructure than their electrical transmission counterparts.

Table 6-4 - Transmission infrastructure cost comparison (state-owned infra included)

Case ID	Topology	Collection infrastructure	Export infrastructure	CAPEX	OPEX[1]	LCOH*
TN-1P	Onshore Centralized	Array cables	HVAC (2x1 substations, 3 cables)	252 M€	123 M€	0.37 €/kg H2
TN-1A	Onshore Centralized	Array cables	HVAC (2x1 substations, 3 cables)	252 M€	123 M€	0.36 €/kg H2
TN-2P	Offshore Centralized	Array cables	H2 pipeline (10.8")	203 M€	67 M€	0.31 €/kg H2
TN-2A	Offshore Centralized	Array cables	H2 pipeline (10.8")	209 M€	68 M€	0.31 €/kg H2
TN-3P	Offshore Decentralized	H2 array pipelines	H2 pipeline (10.8")	121 M€	25 M€	0.18 €/kg H2
TN-3A	Offshore Decentralized	H2 array pipelines	H2 pipeline (10.8")	123 M€	26 M€	0.18 €/kg H2

* Only including transmission infra (array cables/pipelines, HV transmission, hydrogen pipelines)

1. Lifetime discounted OPEX estimates

The omission of the state-owned part of the transport infrastructure (see Figure 6-1) results in a reduction in LCOH of 0.03 – 0.14 €/kg H2 (10% – 38%). In this scenario, the hydrogen transmission options are 20% – 24% more expensive (case 2, offshore centralized) or 31% – 32% cheaper (case 3, offshore decentralized) in terms of levelized cost of hydrogen of the transmission infrastructure than their electrical transmission counterparts. This is caused by the fact that a hydrogen production platform can only host 800 MW of electrolysis capacity, and thus two 500 MW platforms are needed to convert the 1 GW of wind power. This is more expensive than a single HVAC substation of 1 GW. In the case of the offshore decentralized topology, this disadvantage is not present and the omission of array cables (replaced by array pipelines) leads to an extra reduction in cost.

Table 6-5 - Transmission infrastructure cost comparison (state-owned infra omitted)

Case ID	Topology	Collection infrastructure	Export infrastructure	CAPEX	OPEX	LCOH*
TN-1P	Onshore Centralized	Array cables	HVAC (2x1 substations, 3 cables)	149 M€	3 M€	0.23 €/kg H2
TN-1A	Onshore Centralized	Array cables	HVAC (2x1 substations, 3 cables)	149 M€	3 M€	0.22 €/kg H2
TN-2P	Offshore Centralized	Array cables	H2 pipeline (10.8")	180 M€	16 M€	0.27 €/kg H2
TN-2A	Offshore Centralized	Array cables	H2 pipeline (10.8")	186 M€	16 M€	0.27 €/kg H2
TN-3P	Offshore Decentralized	H2 array pipelines	H2 pipeline (10.8")	101 M€	21 M€	0.15 €/kg H2
TN-3A	Offshore Decentralized	H2 array pipelines	H2 pipeline (10.8")	123 M€	26 M€	0.18 €/kg H2

* Only including transmission infra (array cables/pipelines, HV transmission, hydrogen pipelines)

Note that the presented levelized cost comparison only applies to the Tamil Nadu farm with its specifics such as wind profile, water depth and distance to shore. For a more elaborate comparison of transport vectors please see section 6.5.

5.3.6 Efficiency

As can be seen in Figure 6-10 below, the value chain with the highest efficiency is 3A, this is mainly caused by the decentralized topology where the conversion of electricity to hydrogen happens as close as possible to the source, with relatively little downstream losses due to the pipeline transport. Furthermore, the assumption that for 2030 pressurized alkaline electrolysers have higher (beginning of life) efficiency and lower degradation shows a slight difference between the P and A cases.

The onshore centralized case shows the lowest overall efficiency due to the marginally larger transport losses of electricity transport through cables versus gas transport through pipelines at this distance to shore.

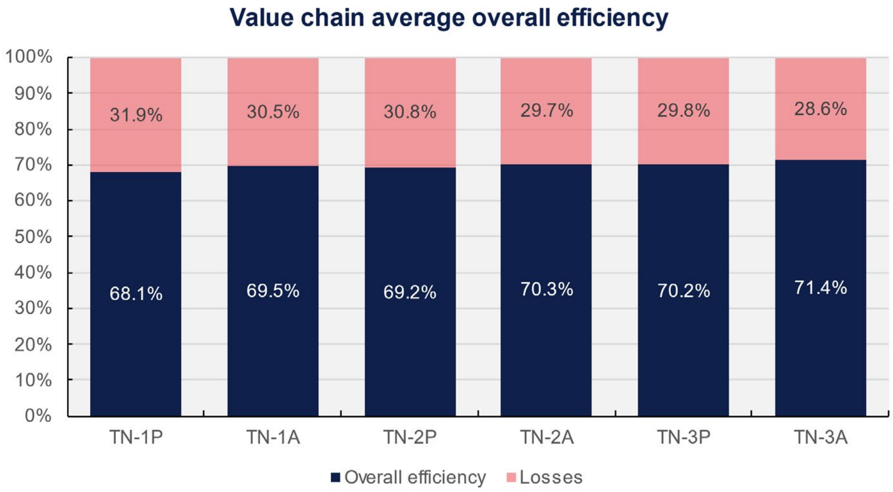


Figure 6-10 Overall efficiency of wind-to-hydrogen value chains for Tamil Nadu (averaged over project lifetime)

5.3.7 Hydrogen yield

As can be seen in Figure 6-11Figure 6-10 below, the amount of hydrogen that can be generated from the Tamil Nadu wind farm ranges on average from 71.1 to 74.5 kilotons of hydrogen per year, depending on the selected topology and electrolyser technology. This difference between the cases is mainly caused by differences in transport efficiency and electrolyser efficiency (degradation).

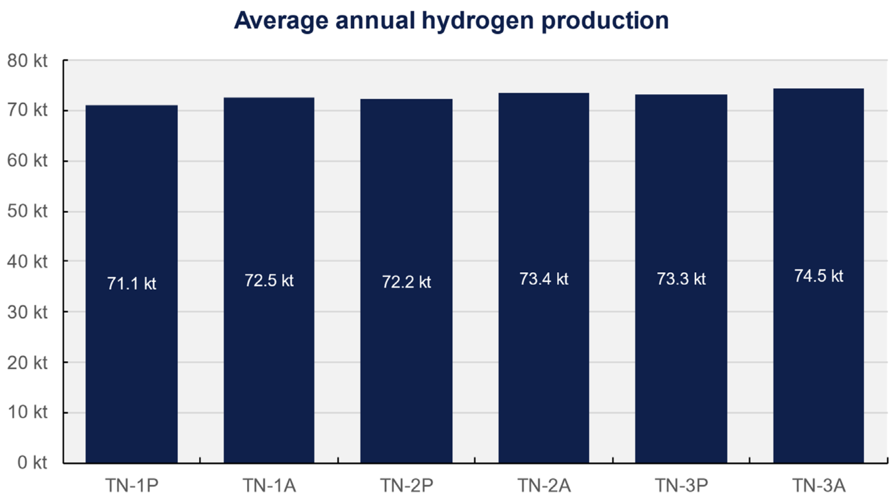


Figure 6-11 - Average annual hydrogen production [kt H2] for the analysed cases

Degradation

An example of a yearly profile can be seen in Figure 6-12, there the decrease in hydrogen production is caused by the efficiency degradation of the electrolyser stacks. In the year 2050, the threshold for degradation (typically ~10% efficiency loss, resulting in individual cell voltages of >2.0V causing unwanted side reactions) is exceeded and stack replacement is triggered.

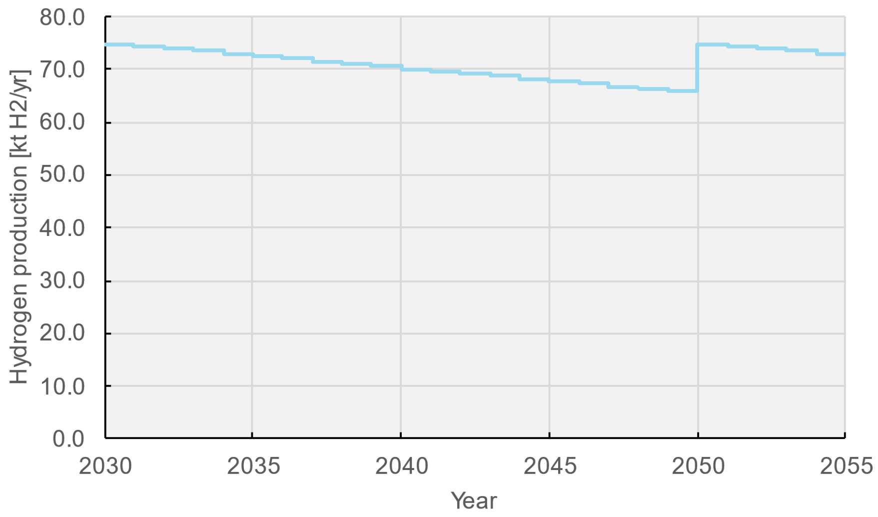


Figure 6-12 Yearly hydrogen production profile for case 1P, showing efficiency degradation of the electrolyser stacks and replacement in project year 20

The fact that the stack replacement is triggered with less than 1/3rd of the project lifetime remaining is an indication that additional optimisation can be performed in sizing the electrolyser stacks. For the onshore centralized case, downsizing the hydrogen plant results in a non-linear [7] increase in the amount of full-load hours of the electrolyser, triggering earlier degradation (optimally near ½ of the project lifetime). For the offshore cases with no access to a grid, balancing with Battery Energy Storage Systems (BESS) and/or hydrogen fuel cells (plus storage) will need to be undertaken in case of a <100% sizing of the electrolyser with respect to the wind generation capacity. This optimisation can be performed in a future study.

Hourly profiles

As explicitly calculated in the model, the hydrogen generation profile will follow that of the wind. This is illustrated in Figure 6-13. Therefore, depending on end-user requirements hydrogen storage will need to be included to generate a more flat profile.

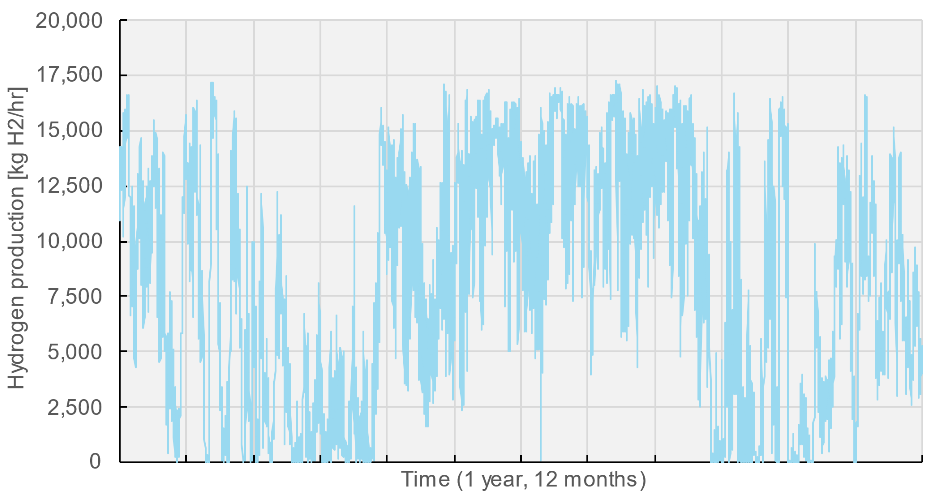


Figure 6-13: Hourly hydrogen production profile from Tamil Nadu wind farm for one year

Storage

Often, industrial offtakes require a (near) flat delivery profile. In order to achieve this, large-scale hydrogen storage is needed to buffer the differences between supply and demand. A first estimate of hydrogen storage requirement is generated by taking the hourly generation profile for the wind farm and

[7] Non-linearity is induced by the wind distribution, with a <100% sized electrolyser, part of the electricity generated by the wind farm will need to be sold to the grid, curtailed or buffered by BESS since not all power can be fed to the hydrogen plant.

calculating the minimum storage size that would be required to deliver the average hourly production for all hours in the year, the storage acts as a buffer between supply (varying) and demand (constant). Please note that no hydrogen storage has been included in the cost modeling.

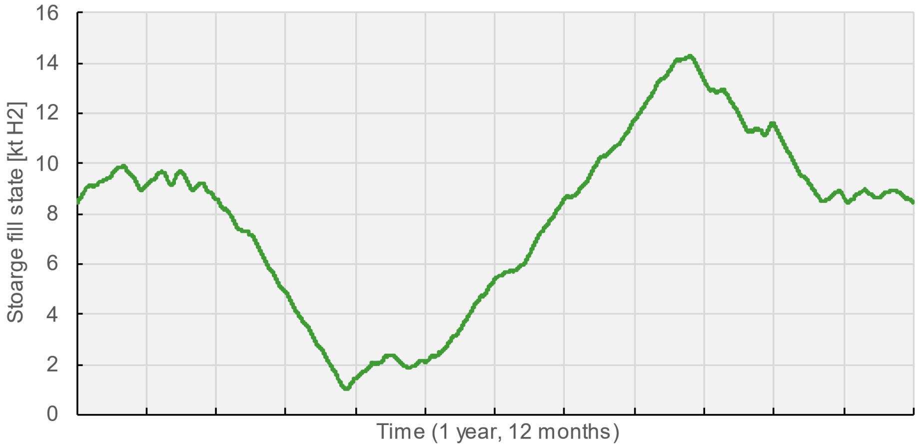


Figure 6-14 - Hydrogen storage fill state for generating flat production profile in Tamil Nadu 1 GW wind farm

As can be seen in Figure 6-14, the storage shows a strong seasonal fluctuation. The maximum of the graph determines the required storage size, in this case, it amounts to ~15 kilotons of hydrogen. In total, ~30% of the yearly produced hydrogen will be stored for some amount of time. This amount of storage can reasonably only be cost-effectively realised using geological storage. This means to lower the storage size can be twofold: on the production side and on the demand side. On the production side, an energy management system can be optimised to curtail power when there is no hydrogen demand, or in extreme cases hydrogen can be flared. On the demand side, many industrial offtakes are investigating demand-side flexibility, where downstream assets are designed to handle (some of) the fluctuations resulting from the wind profile. Lastly, when feeding into a common shared infrastructure such as a hydrogen backbone, fluctuation might be mitigated by the larger hydrogen transport infrastructure and storage facilities.

5.4 Case study – Gujarat

In this case study, the three offshore hydrogen production topologies in Chapter 3 are compared (denoted by numbers 1 – 3) for the Gujarat 1 GW wind farm. Furthermore, both PEM and Pressurized Alkaline technologies are analysed (denoted by the letter P/A). The case study will compare Levelized Cost of Hydrogen, Capex, Opex, Levelized Cost of Electricity, Transmission infrastructure cost, Value chain efficiency, and Hydrogen yield.

5.4.1 Levelized Cost of Hydrogen

As can be seen in Figure 6-15 below, the centralized production topologies (1 & 2) feature a more attractive LCOH compared to the decentralized production topology (3). Furthermore, it can be overserved that Pressurized Alkaline (A) features a more cost-effective profile than PEM (P) for 2030. It should be noted that the offshore production topologies come with relatively large uncertainties with regard to the cost of offshore installation and maintenance, as well as the “marine readiness” of electrolysis equipment in general for 2030.

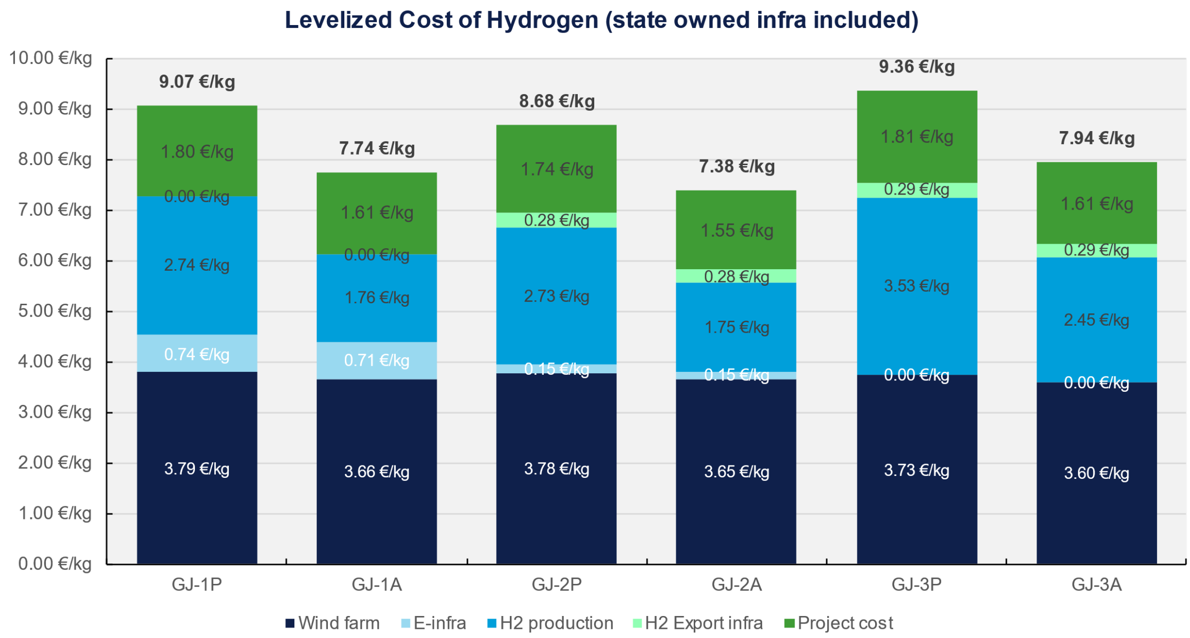


Figure 6-15 Levelized costs of Hydrogen (LCOH) of wind-to-hydrogen value chains for the Gujarat 1 GW wind farm (state-owned infra included)

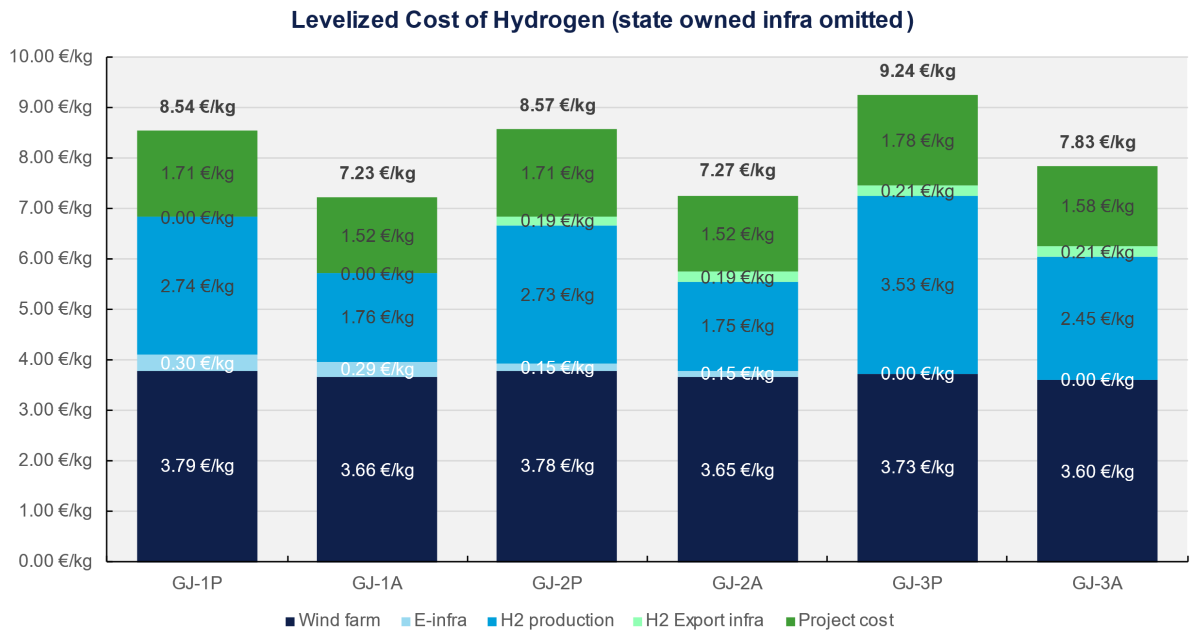


Figure 6-16 Levelized cost of Hydrogen (LCOH) of wind-to-hydrogen value chains for the Gujarat 1 GW wind farm (state-owned infra omitted)

To take a closer look at the most cost-effective option: GJ-2A – offshore centralized hydrogen production, using pressurized alkaline electrolysers. Figure 6-17 features a cost split per category and highlights the CAPEX and OPEX share of each category.

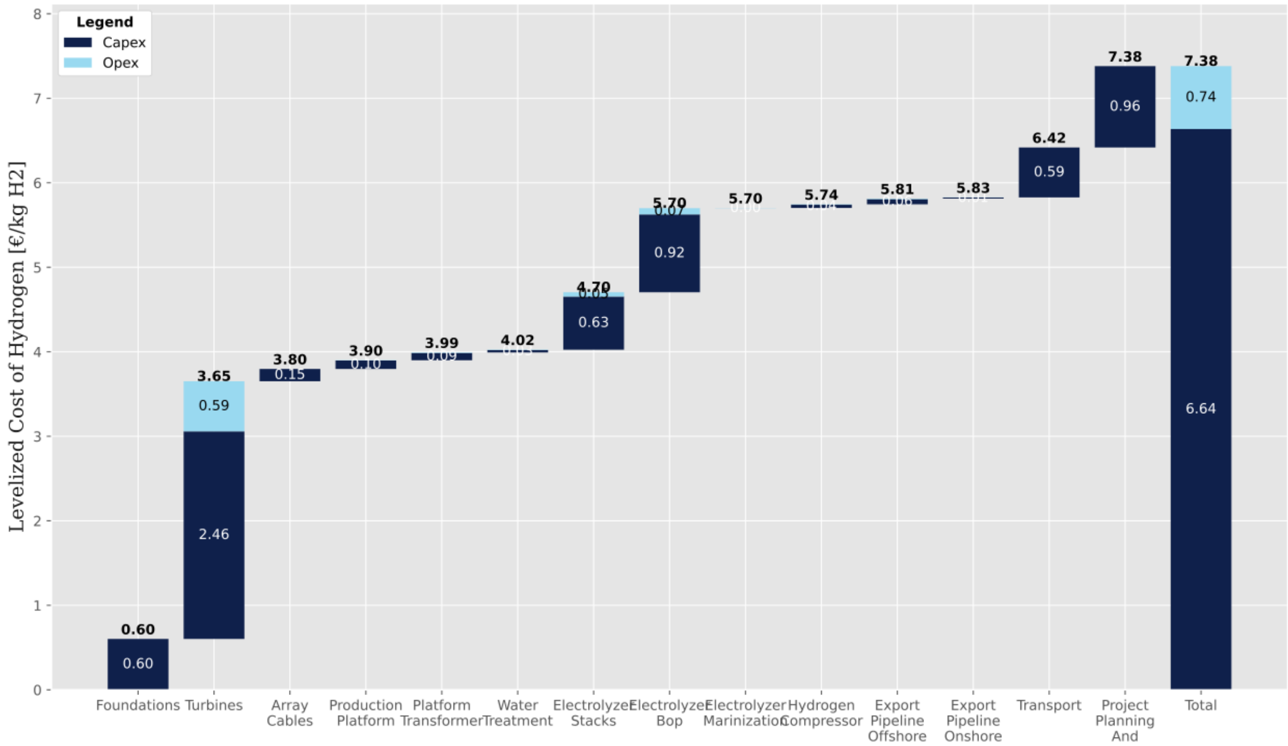


Figure 6-17 Detailed Levelized cost of Hydrogen (LCOH) breakdown for the Gujarat 1 GW wind farm. Case 2A – offshore centralized with pressurized alkaline technology – split between cost categories and CAPEX/OPEX.

Compared to the Tamil Nadu case study, the Gujarat wind farm has lesser wind resources and therefore also results in a lower annual hydrogen production (25% – 26% lower). This will have a large impact on the levelized cost of hydrogen (30% – 35% higher than in Tamil Nadu).

5.4.2 CAPEX

As can be seen in Figure 6-18, the main differences between the cases are between the CAPEX of PEM (P) and Pressurized alkaline (A) electrolysers. Furthermore, differences can be observed between the offshore production topologies, generally featuring a higher unit cost and installation cost. It should be noted that the offshore costs for hydrogen production equipment are prone to large uncertainty.

Upon comparing the CAPEX of the electrical transmission infrastructure with the hydrogen gas transport infrastructure, it becomes evident that hydrogen transport by pipeline is slightly cheaper in terms of transport infrastructure cost, but at the relatively low distance to the shore of the Gujarat wind farm, this difference just enough to offset the higher costs for offshore production. In this case, energy transport through pipelines has a cost benefit over direct electricity transport. This is further analysed in section 6.4.5.

Upon omission of the state-owned part of the transport infrastructure (see Figure 6-1), this difference becomes negligible. This is mainly driven by the relatively large cost of the hydrogen production platforms in case 2.

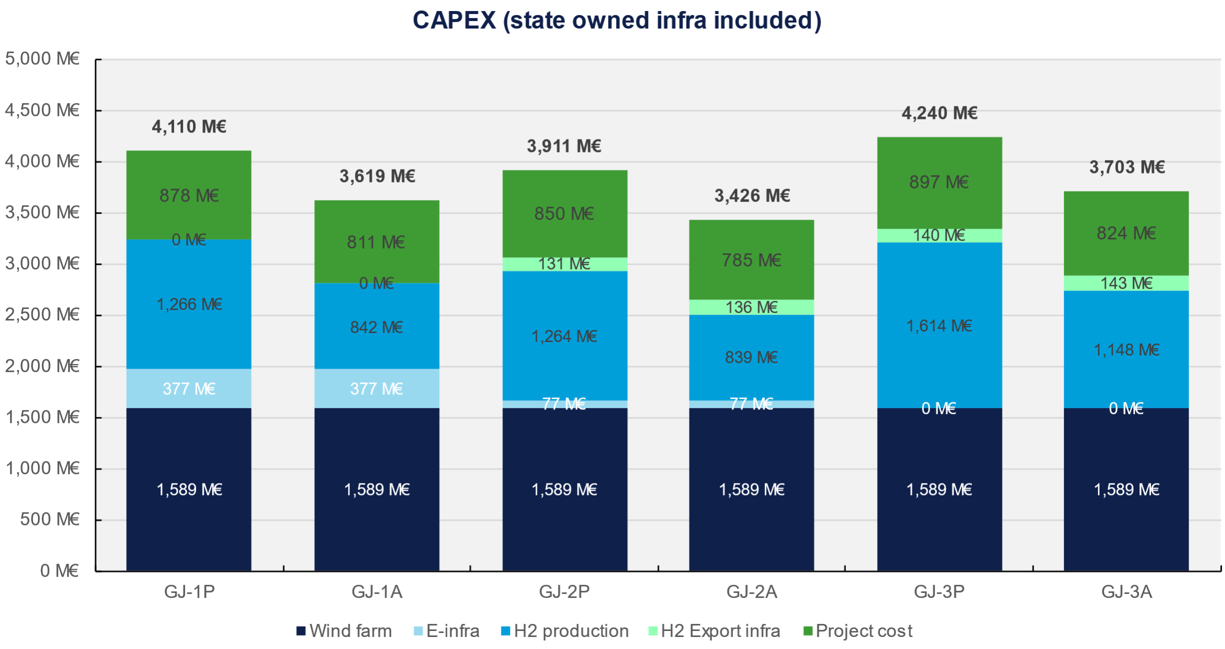


Figure 6-18 – CAPEX (Absolute, 2023) of wind-to-hydrogen value chains for the Gujarat 1GW wind farm (state-owned infra included)

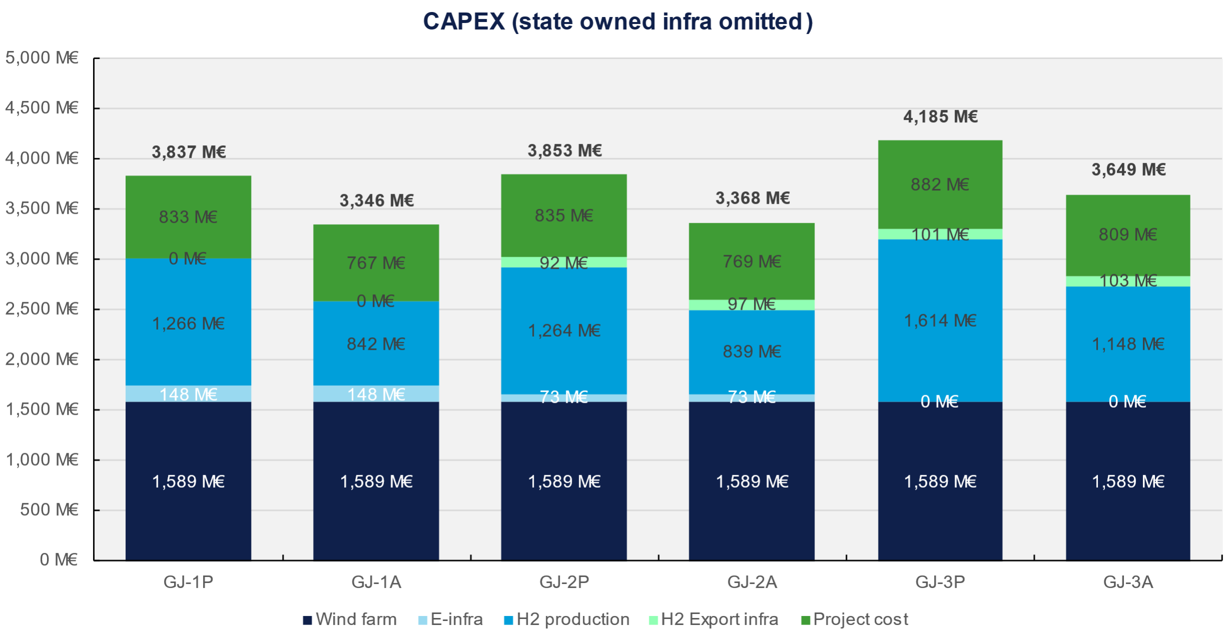


Figure 6-19 – CAPEX (Absolute, 2023) of wind-to-hydrogen value chains for the Gujarat 1GW wind farm (state-owned infra omitted)

5.4.3 OPEX

As can be seen in Figure 6-21 (on the next page), the main differences between the cases are between the OPEX of PEM (P) and Pressurized alkaline (A) electrolysers. Furthermore, differences can be observed between the offshore production topologies, generally featuring a higher cost for maintenance. It should be noted that the offshore maintenance cost for hydrogen production equipment is prone to large uncertainty. Upon comparing the OPEX of the electrical transmission infrastructure with the hydrogen gas transport infrastructure, it becomes evident that hydrogen transport by pipeline is cheaper.

Upon comparing the OPEX of the Tamil Nadu farm to the OPEX of the Gujarat farm, it becomes evident that the low amount of full load hours in the Gujarat farm causes the degradation threshold of the electrolysers not to be exceeded during the project lifetime, and therefore no stack replacement has to take place. This saves some investment during the later stages of the project. Therefore, the total OPEX of the Gujarat farm (including hydrogen production) is lower than that of the Tamil Nadu farm. Whether this lifetime can actually be achieved critically depends on the performance guarantees that are agreed upon with the electrolyser manufacturer in the context of the project.

5.4.4 Levelized Cost of Electricity

An indicative levelized cost of electricity is calculated for all cases. Here it becomes evident that the omission of the state-owned high-voltage transmission infrastructure has a significant impact on the LCOE. The Offshore Centralized topology is slightly more expensive than the Offshore Decentralized topology due to the requirement for array cables feeding power from the turbines to the hydrogen production platforms. The omission of the state-owned part of the electrical infrastructure (see Figure 6-1) for the Onshore Centralized case results in a reduction in LCOE of 8.20 €/MWh (8%). In the other cases there is no cost reduction as the export cables and onshore substation are not included in those topologies anyhow.

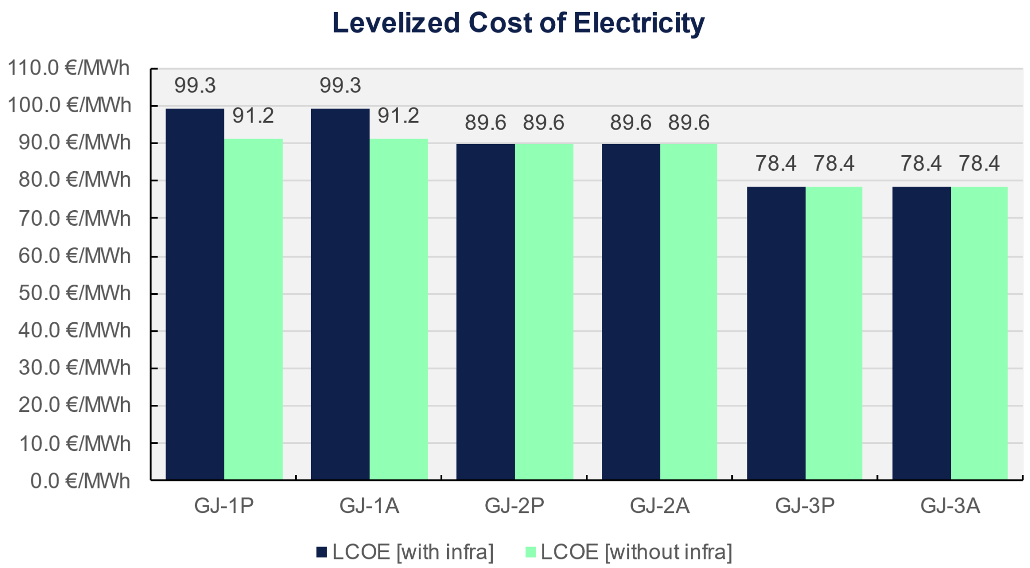


Figure 6-20 Levelized Cost of Electricity (LCOE) of wind-to-hydrogen value chains for Tamil Nadu 1 GW wind farm (with- and without state-owned infrastructure included)

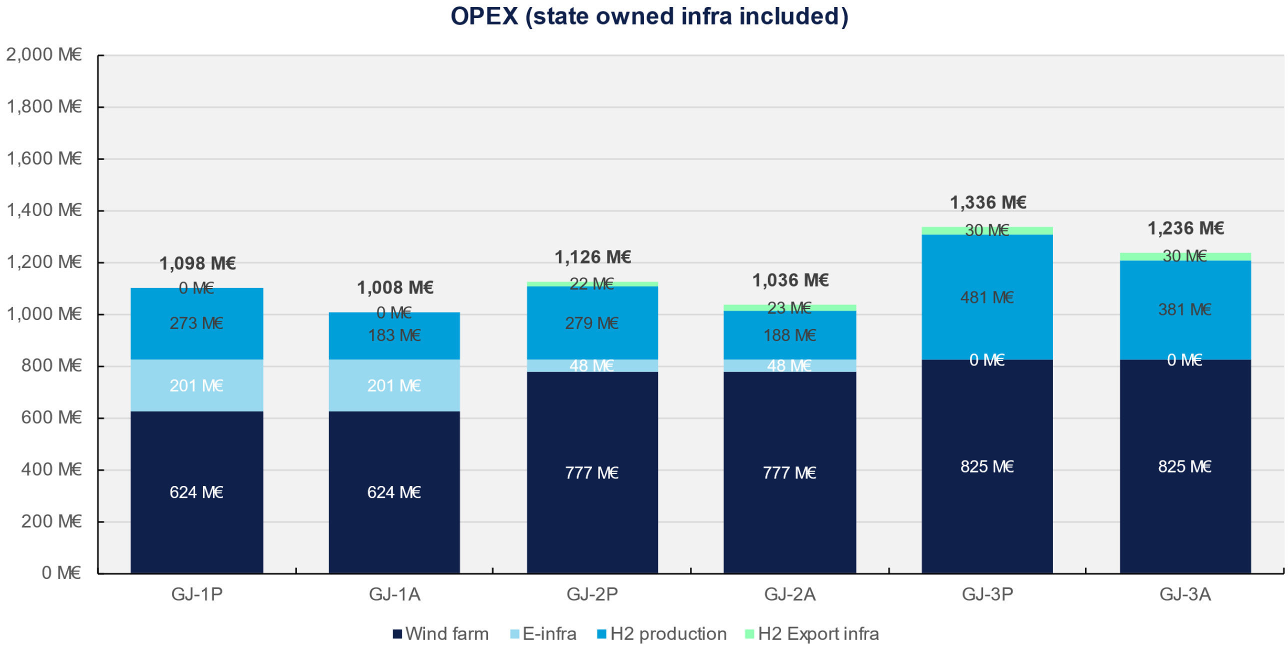


Figure 6-21 – OPEX (Absolute, 2023) of wind-to-hydrogen value chains for Gujarat 1 GW wind farm (state-owned infra included)

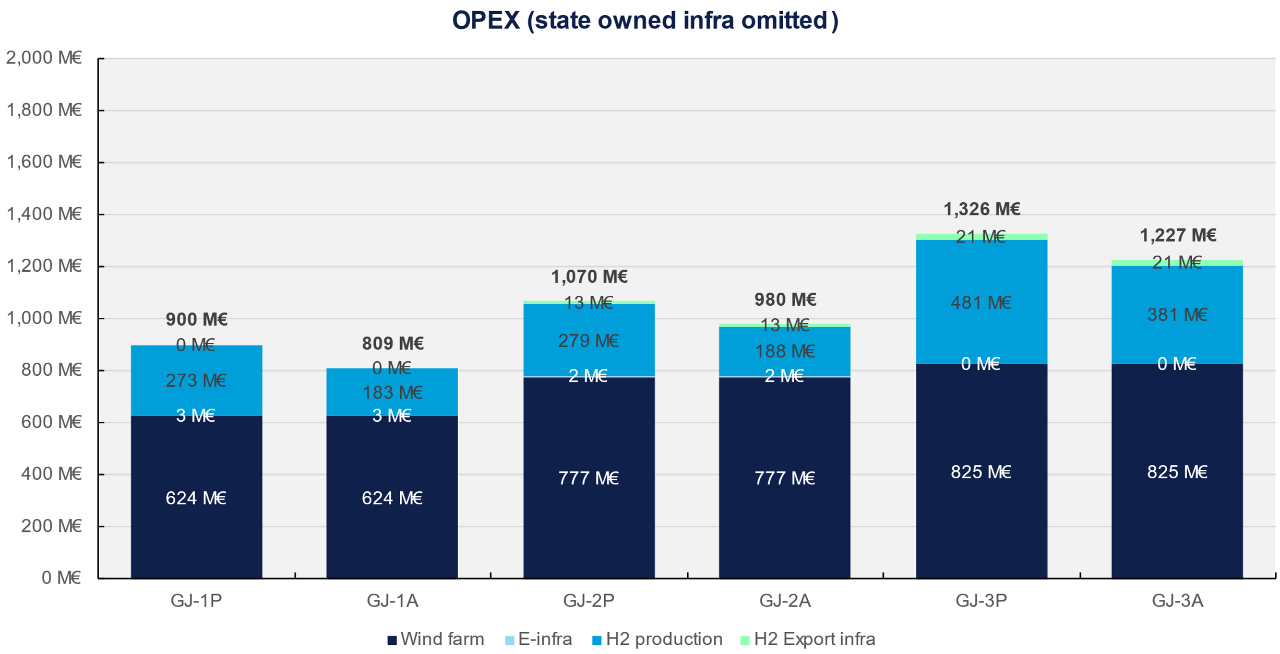


Figure 6-22 – OPEX (Absolute, 2023) of wind-to-hydrogen value chains for Gujarat 1 GW wind farm (state-owned infra omitted)

5.4.5 Transmission infrastructure cost

Upon comparing the total transmission infrastructure cost of the analysed value chains, it becomes evident that the hydrogen transmission options are 41% – 61% cheaper in terms of the levelized cost of hydrogen of the transmission infrastructure than their electrical transmission counterparts.

Table 6-6 - Transmission infrastructure cost comparison (state-owned infra included)

Case ID	Topology	Collection infrastructure	Export infrastructure	CAPEX	OPEX	LCOH*
GJ-1P	Onshore Centralized	Array cables	HVAC (2x1 substations, 3 cables)	377 M€	201 M€	0.74 €/kg H2
GJ-1A	Onshore Centralized	Array cables	HVAC (2x1 substations, 3 cables)	377 M€	201 M€	0.71 €/kg H2
GJ-2P	Offshore Centralized	Array cables	H2 pipeline (10.8")	208 M€	70 M€	0.43 €/kg H2
GJ-2A	Offshore Centralized	Array cables	H2 pipeline (10.8")	213 M€	71 M€	0.42 €/kg H2
GJ-3P	Offshore Decentralized	H2 array pipelines	H2 pipeline (10.8")	140 M€	30 M€	0.29 €/kg H2
GJ-3A	Offshore Decentralized	H2 array pipelines	H2 pipeline (10.8")	143 M€	30 M€	0.29 €/kg H2

* Only including transmission infra (array cables/pipelines, HV transmission, hydrogen pipelines)

The omission of the state-owned part of the transport infrastructure (see Figure 6-1) results in a reduction in LCOH of 0.08 – 0.44 €/kg H2 (20% – 59%). In this scenario, the hydrogen transmission options are 12% – 15% more expensive (case 2, offshore centralized) or 30% – 31% cheaper (case 3, offshore decentralized) in terms of the levelized cost of hydrogen of the transmission infrastructure than their electrical transmission counterparts. This is caused by the fact that a hydrogen production platform can only host 800 MW of electrolysis capacity, and thus two 500 MW platforms are needed to convert the 1 GW of wind power. This is more expensive than a single HVAC substation of 1 GW. In the case of the offshore decentralized topology, this disadvantage is not present and the omission of array cables (replaced by array pipelines) leads to an extra reduction in cost.

Table 6-7 - Transmission infrastructure cost comparison (state-owned infra omitted)

Case ID	Topology	Collection infrastructure	Export infrastructure	CAPEX	OPEX	LCOH*
GJ-1P	Onshore Centralized	Array cables	HVAC (2x1 substations, 3 cables)	148 M€	3 M€	0.30 €/kg H2
GJ-1A	Onshore Centralized	Array cables	HVAC (2x1 substations, 3 cables)	148 M€	3 M€	0.29 €/kg H2
GJ-2P	Offshore Centralized	Array cables	H2 pipeline (10.8")	165 M€	14 M€	0.34 €/kg H2
GJ-2A	Offshore Centralized	Array cables	H2 pipeline (10.8")	170 M€	15 M€	0.34 €/kg H2
GJ-3P	Offshore Decentralized	H2 array pipelines	H2 pipeline (10.8")	101 M€	21 M€	0.21 €/kg H2
GJ-3A	Offshore Decentralized	H2 array pipelines	H2 pipeline (10.8")	103 M€	21 M€	0.21 €/kg H2

* Only including transmission infra (array cables/pipelines, HV transmission, hydrogen pipelines)

Note that the presented levelized cost comparison only applies to the Gujarat farm with its specifics such as wind profile, water depth and distance to shore. For a more elaborate comparison of transport vectors please see section 6.5.

5.4.6 Efficiency

As can be seen in Figure 6-23 below, the value chain with the highest efficiency is 3A, this is mainly caused by the decentralized topology where the conversion of electricity to hydrogen happens as close as possible to the source, with relatively little downstream losses due to the pipeline transport. Furthermore, the assumption that for 2030 pressurized alkaline electrolysers have higher (beginning of life) efficiency and lower degradation shows a slight difference between the P and A cases.

The onshore centralized case shows the lowest overall efficiency due to the marginally larger transport losses of electricity transport through cables versus gas transport through pipelines at this distance to shore.

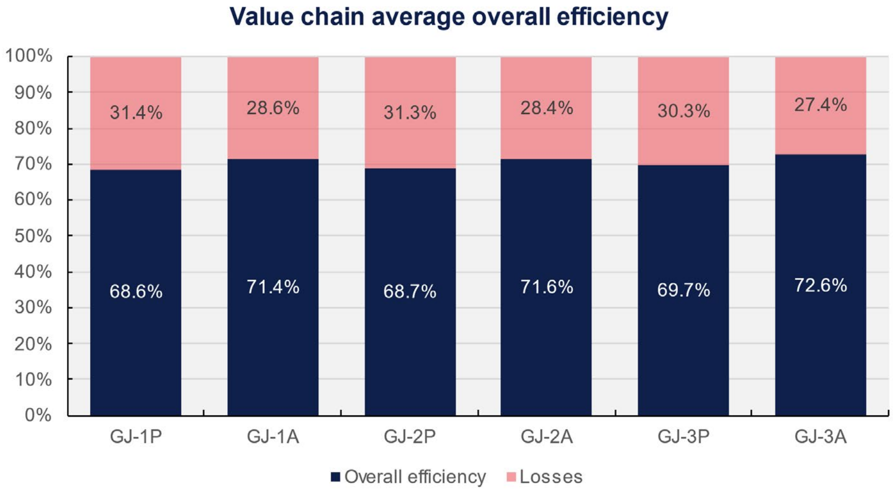


Figure 6-23 Overall efficiency of wind-to-hydrogen value chains for Tamil-Nadu (averaged over project lifetime)

5.4.7 Hydrogen yield

The amount of hydrogen that can be generated from the Tamil Nadu wind farm ranges on average from 71.1 to 74.5 kilotons of hydrogen per year, depending on the selected topology and electrolyser technology. This difference between the cases is mainly caused by differences in transport efficiency and electrolyser efficiency (degradation).

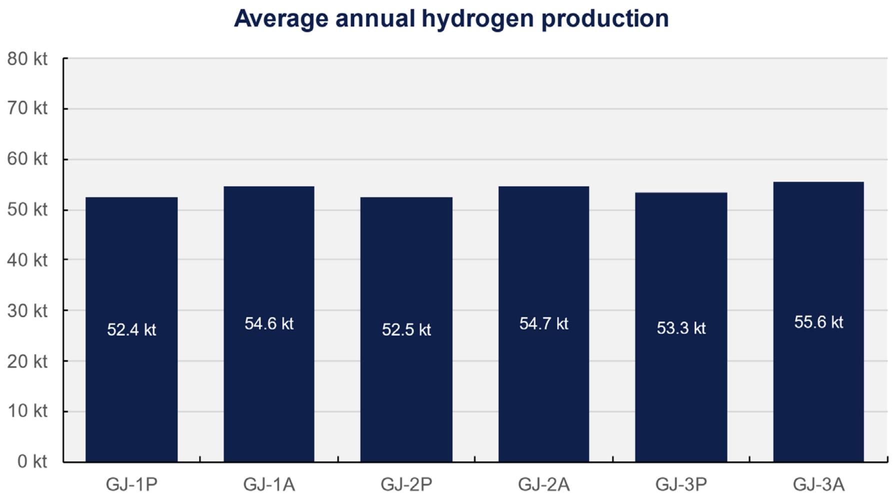


Figure 6-24 - Average annual hydrogen production [kt H2] for the analysed cases

Compared to the Tamil Nadu case study, this wind farm has lesser wind resources and therefore also results in a lower annual hydrogen production (25% lower). This will have a large impact on the levelized cost of hydrogen (30% – 35% higher).

Degradation

An example of a yearly profile can be seen in Figure 6-25, there the decrease in hydrogen production is caused by the efficiency degradation of the electrolyser stacks. Due to the low wind resource, the threshold for degradation (typically ~10% efficiency loss, resulting in individual cell voltages of >2.0V causing unwanted side reactions) is never exceeded during the project lifetime, and as such no stack replacement is triggered.

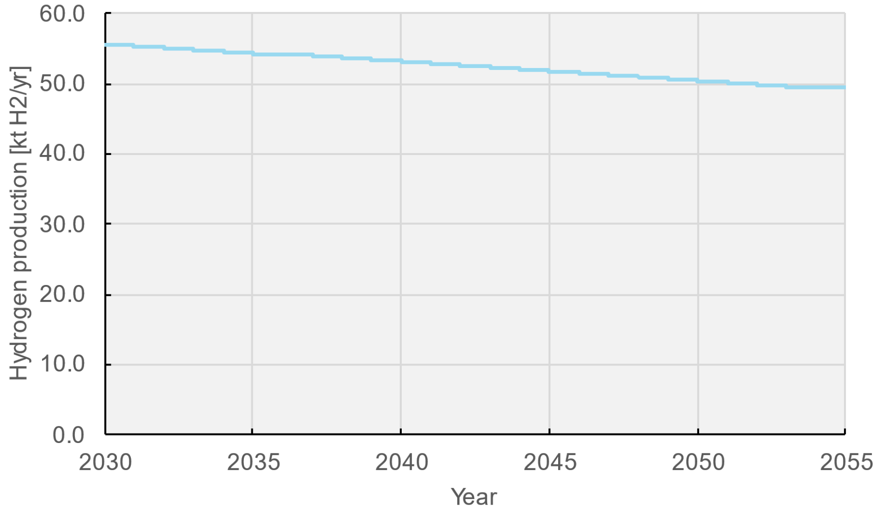


Figure 6-25 Yearly hydrogen production profile for case GJ-1P, showing efficiency degradation of the electrolyser stacks and replacement in project year 20

Hourly profiles

As explicitly calculated in the model, the hydrogen generation profile will follow that of the wind. This is illustrated in Figure 6-26. Therefore, depending on end-user requirements hydrogen storage will need to be included to generate a more flat profile.

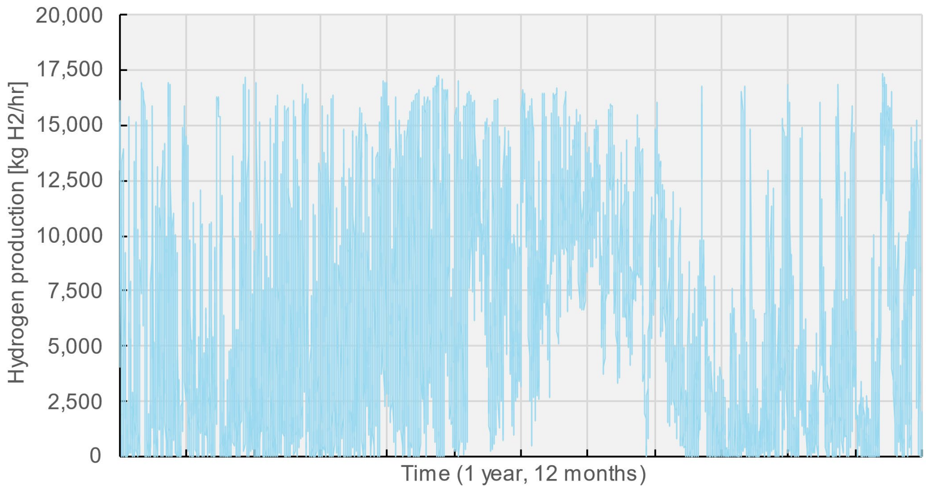


Figure 6-26: Hourly hydrogen production profile from Tamil Nadu wind farm for one year

Storage

Often, industrial off-takers require a (near) flat delivery profile. In order to achieve this, large-scale hydrogen storage is needed to buffer the differences between supply and demand. A first estimate of hydrogen storage requirement is generated by taking the hourly generation profile for the wind farm and calculating the minimum storage size that would be required to deliver the average hourly production for all hours in the year, the storage acts as a buffer between supply (varying) and demand (constant). Please note that no hydrogen storage has been included in the cost modelling.

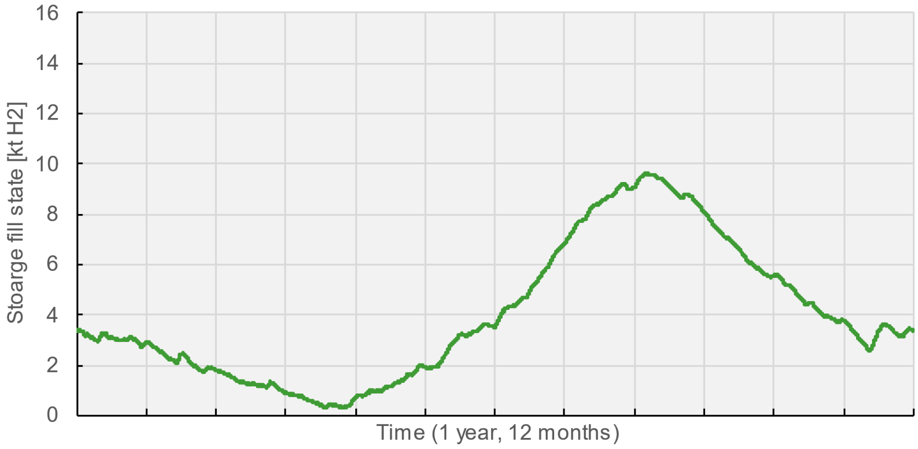


Figure 6-27 - Hydrogen storage fill state for generating flat production profile in Gujarat 1 GW wind farm

As can be seen in Figure 6-27, the storage shows a strong seasonal fluctuation. The maximum of the graph determines the required storage size, in this case, it amounts to ~10 kilotons of hydrogen. In total, ~35% of the yearly produced hydrogen will be stored for some amount of time. This amount of storage can reasonably only be cost-effectively realised using geological storage. This means to lower the storage size can be twofold: on the production side and on the demand side. On the production side, an energy management system can be optimised to curtail power when there is no hydrogen demand, or in extreme cases hydrogen can be flared. On the demand side, many industrial off-takers are investigating demand-side flexibility, where downstream assets are designed to handle (some of) the fluctuations resulting from the wind profile. Lastly, when feeding into a common shared infrastructure such as a hydrogen backbone, fluctuation might be mitigated by the larger hydrogen transport infrastructure and storage facilities.

5.5 Case study – Energy transmission vector: electricity vs. pipeline

In order to compare the cost-effectiveness of electricity transport versus hydrogen pipeline transport, a case study is presented which gives insight into the cost dynamics of these energy transmission vectors. Critically, this case study only considers the cost of the transport infrastructure and as such represents only partially the true levelized cost of hydrogen. This means that any hydrogen production equipment such as electrolyzers are excluded from the analysis. Nonetheless, this can give a future owner/operator of the transmission infrastructure insight into the levelized costs associated with both forms of energy transport, as a function of distance to shore and wind farm capacity. Table 6-8 gives insight into the cost components that are included/excluded in the following scenarios that are compared:

1. HVAC transmission
2. HVDC transmission
3. H2 Pipeline transmission

Table 6-8 - Categories and components for the electricity vs. pipeline case study

Main Category	Components	Transmission type
Electrical transmission infrastructure	Array cables	Electricity (HVAC / HVDC)
	Substation offshore	Electricity (HVAC / HVDC)
	Export cable	Electricity (HVAC / HVDC)
	Substation onshore	Electricity (HVAC / HVDC)
	66/33 kV transformer	Pipeline
Hydrogen production	Turbine add-on structure	Excluded
	Hydrogen production platform	Pipeline
	Electrolyser power supply	Excluded
	Water Treatment & Cooling	Excluded
	Electrolyser Stacks	Excluded
	Electrolyser Balance of Plant	Excluded
	Hydrogen compressors	Pipeline
Hydrogen transmission infrastructure	Hydrogen array pipelines	Pipeline
	Hydrogen export pipeline offshore	Pipeline
	Hydrogen export pipeline onshore	Pipeline
Project costs	Project planning & contingency	Excluded
	Transport	Excluded

Further assumptions for this case study are:

- Lifetime: 25 years
- Discount rate: 10%
- Wind farm capacity: **0.5 GW – 9 GW** (0.5 GW steps)
- Distance windfarm to shore (offshore): **10 km – 500 km** (10 km steps)
- Distance onshore: 0 km (onshore transmission is effectively excluded from the analysis)
- Any energy lost in transmission (Array cables, HVAC / HVDC transmission) or compression (Pipeline) is not available for hydrogen production and will therefore result in lower total hydrogen production and subsequently a higher Levelized Cost of Hydrogen. The total hydrogen production in case of 100% efficiency of the transmission value chain is assumed to be 90.5 kilotons of hydrogen per year, per GW of installed wind capacity.
- It is explicitly assumed that the final product is hydrogen and subsequent conversion losses of transforming hydrogen back to electricity are not included. This would fundamentally alter the outcomes of the analysis. DNV would generally advise against transforming hydrogen back to electricity unless unavoidable. In that case, it would always be better to use the electricity directly.

5.5.1 Electricity – HVAC transmission

The cost for HVAC transmission infrastructure is comprised of Array cables (66 kV), HVAC substation (66/220 kV, offshore), Export cables (220 kV, offshore), Export cables (220 kV, onshore), and HVAC substation (220/33 kV, onshore).

DNVs proprietary software Renewables. Architect was used to calculate cost and efficiency figures for each case. These can be seen in Table 6-9. For instance, a 1 GW wind farm located at 100 km from shore features an array of cables that cost of 81,200 €/MW, offshore HVAC substation cost of 80,000 €/MW, offshore Export cables cost of 496,500 €/MW, onshore HVAC substation cost of 35,000 €/MW. This specific transmission value chain features an efficiency of 94.5%. This results in a levelized cost of hydrogen of 0.247 €/kg H2.

Table 6-9 – Cost assumptions for HVAC case

Component	CAPEX	CAPEX Unit	OPEX	OPEX Unit
Array cables	Dynamic	€/MW	1.5%	% of CAPEX/yr
HVAC substation, offshore	80,000	€/MW		
Export cables offshore	Dynamic	€/MW		
Export cables onshore	N/A	€/MW		
HVAC substation, onshore	35,000	€/MW		

As a result of the case study, the levelized cost contour (€/kg H2) of the HVAC transmission is plotted as a function of distance to shore (x-axis) and wind farm capacity (y-axis). As can be seen in Figure 6-28, HVAC transmission is considered feasible in the coloured region, and infeasible in the grey region. The upper limit of wind farm capacity is set at 3 GW (until ~120 km distance to shore). The upper limit of distance to shore is set at 250 km, but as the figure shows the levelized cost increases quadratically with increasing distance due to efficiency losses and the need for additional (parallel) export cables.

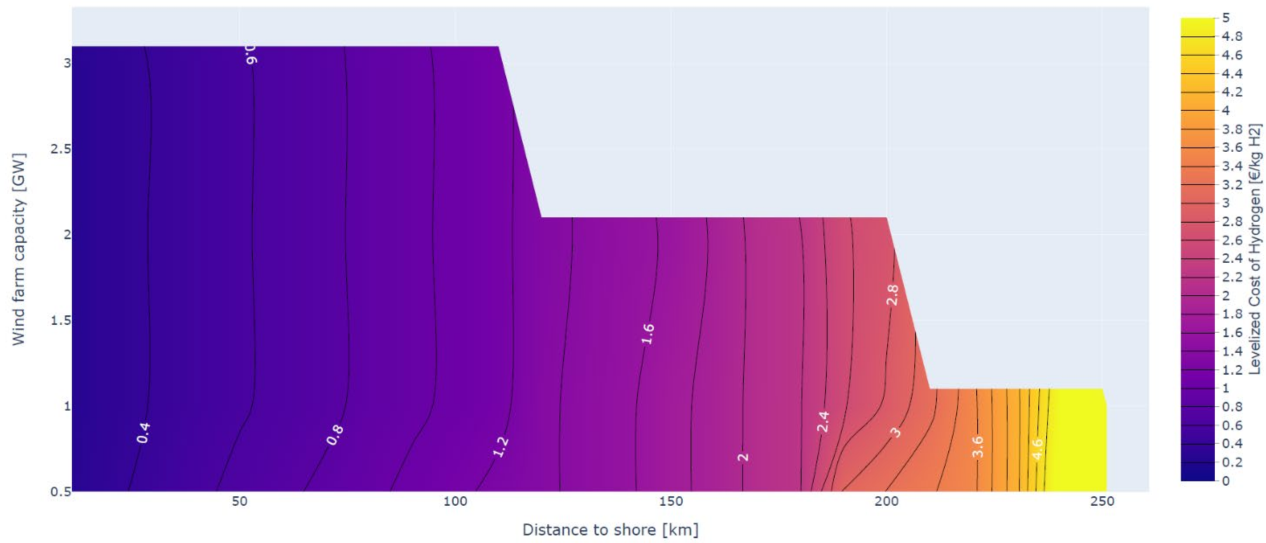


Figure 6-28: Levelized cost contour of HVAC transport infra as a function of distance to shore and wind farm capacity

5.5.2 Electricity – HVDC transmission

The cost for HVDC transmission infrastructure is comprised of Array cables (66 kV), HVDC substation (66/320 kV, offshore), Export cables (320 kV, offshore), Export cables (320 kV, onshore) and HVDC substation (320/33 kV, onshore).

DNVs proprietary software Renewables. Architect was used to calculate cost and efficiency figures for each case. These can be seen in Table 6-10. For instance, a 1 GW wind farm located 100 km from shore features an array of cables that cost of 81,200 €/MW, offshore HVAC substation cost of 685,000 €/MW, offshore Export cables cost of 212,250 €/MW, onshore HVAC substation cost of 200,000 €/MW. This specific transmission value chain features an efficiency of 91.9%. This results in a levelized cost of hydrogen of 1.718 €/kg H2.

Table 6-10 – Cost assumptions for HVDC case

Component	CAPEX	CAPEX Unit	OPEX	OPEX Unit
Array cables	Dynamic	€/MW	2.0%	% of CAPEX/yr
HVDC substation, offshore	200,000	€/MW		
Export cables offshore	Dynamic	€/MW		
Export cables onshore	N/A	€/MW		
HVDC substation, onshore	685,000	€/MW		

As a result of the case study, the levelized cost contour of the HVDC transmission is plotted as a function of distance to shore (x-axis) and wind farm capacity (y-axis). As can be seen in Figure 6-29, HVDC transmission is considered feasible in the colored region. The upper limit of wind farm capacity is set at 10 GW. The upper limit of distance to shore is set at 500 km. As the figure shows, after 1 GW of wind farm capacity costs scale linearly with installed wind farm capacity. Furthermore, the cost increases as the distance to shore increases, mainly due to the HVDC cable cost and to a lesser extent the effect of reduced transport efficiency. It can be observed that the initial cost of HVDC is much higher than that of HVAC, mainly due to the relatively expensive substations. However, with increasing distance to shore, the difference is minimized due to the lower energy losses and cable cost for HVDC.

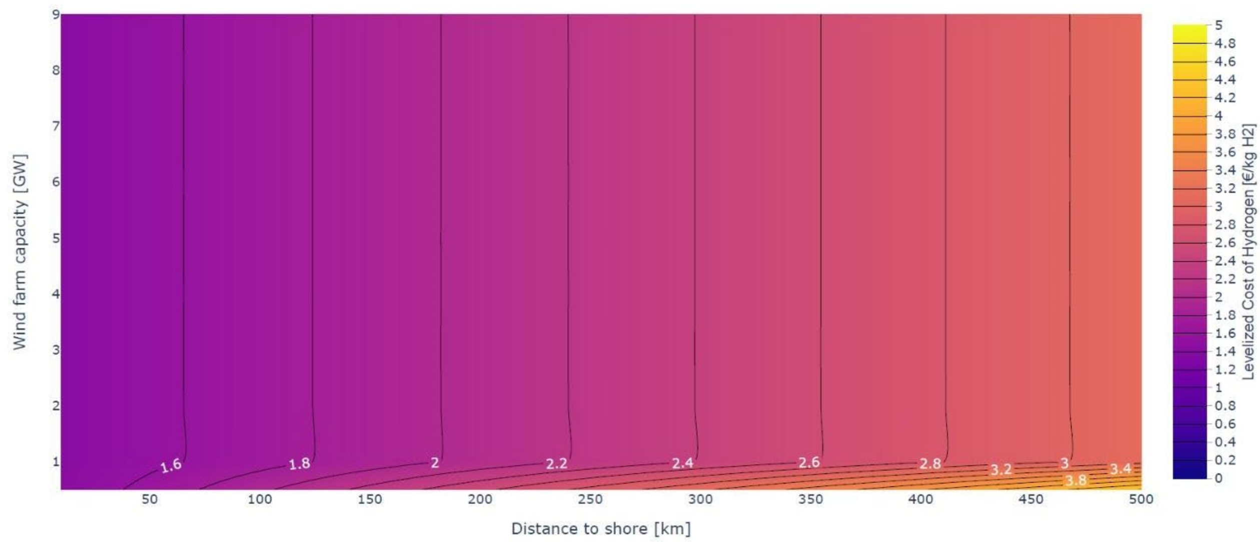


Figure 6-29: Levelized cost contour of HVDC transport infra as a function of distance to shore and wind farm capacity

5.5.3 Hydrogen – Pipeline transmission

The cost for pipeline transmission infrastructure is comprised of Array pipelines, Hydrogen production platform (steel works and foundation), Hydrogen platform transformer (66/33 kV), Export pipeline (hydrogen, offshore), and HVDC substation (offshore). These can be seen in Table 6-11.

DNVs proprietary software Renewables. Architect was used to calculating the most cost-effective combination of pipeline diameter, pipeline pressure, and subsequent compression cost and energy consumption. This resulted in cost and efficiency figures for each case. For instance, a 1 GW wind farm located 100 km from shore features an array pipelines cost of 80,000 €/MW, a Hydrogen production platform cost 65,000 €/MW, a 66/33 kV transformer cost 43,000 €/MW, a Hydrogen compressor cost of 18,000 €/MW, Export pipeline offshore cost of 90,000 €/MW (12 inch OD, 80 bar pressure). This specific transmission value chain features an efficiency of 99.2%. This results in a levelized cost of hydrogen of 0.288 €/kg H2.

Table 6-11 – Cost assumptions for Pipeline case

Component	CAPEX	CAPEX Unit	OPEX	OPEX Unit
Array pipelines	80,000	€/MW	1.0%	% of CAPEX/yr
Hydrogen production platform	65,000	€/MW	0.5%	
66/33 kV transformer	43,000	€/MW	1.0%	
Hydrogen compressor	Dynamic	€/MW	4.0%	
Export pipeline offshore	Dynamic	€/MW	1.0%	
Export pipeline onshore	N/A	€/MW	1.0%	

As a result of the case study, the levelized cost contour of the Pipeline transmission is plotted as a function of distance to shore (x-axis) and wind farm capacity (y-axis). As can be seen in Figure 6-30Figure 6-29, Pipeline transmission is considered feasible in the coloured region (part of the analysis), but can be used to transport even larger capacities over even larger distances using a single pipeline. Please note that Figure 6-30 features the same legend (colour) scale as the HVAC and HVDC cases for the sake of comparison. Figure 6-31 features a more reasonable scaling.

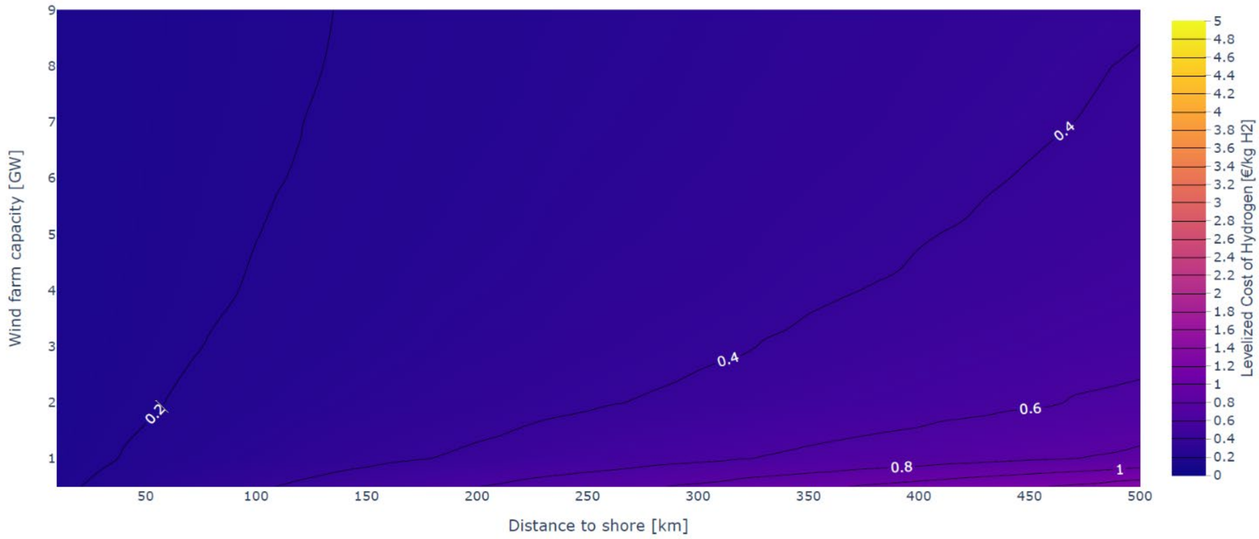


Figure 6-30: Levelized cost contour of Pipeline transport infra as a function of distance to shore and wind farm capacity (max = 5 €/kg H2, same as HVAC / HVDC plot)

Especially when considering the cases with very large wind farm capacities and distances to shore, pipelines are extremely cost-effective. One might conceive situations where hydrogen produced by multiple offshore wind farms is collected in a central location and brought to shore using a single large pipeline. The upper limit of wind farm capacity in this analysis is set at 10 GW, but realistically speaking even larger capacities could be transported. The upper limit of distance to shore is set at 500 km, but realistically speaking hydrogen could be transported over even larger distances.

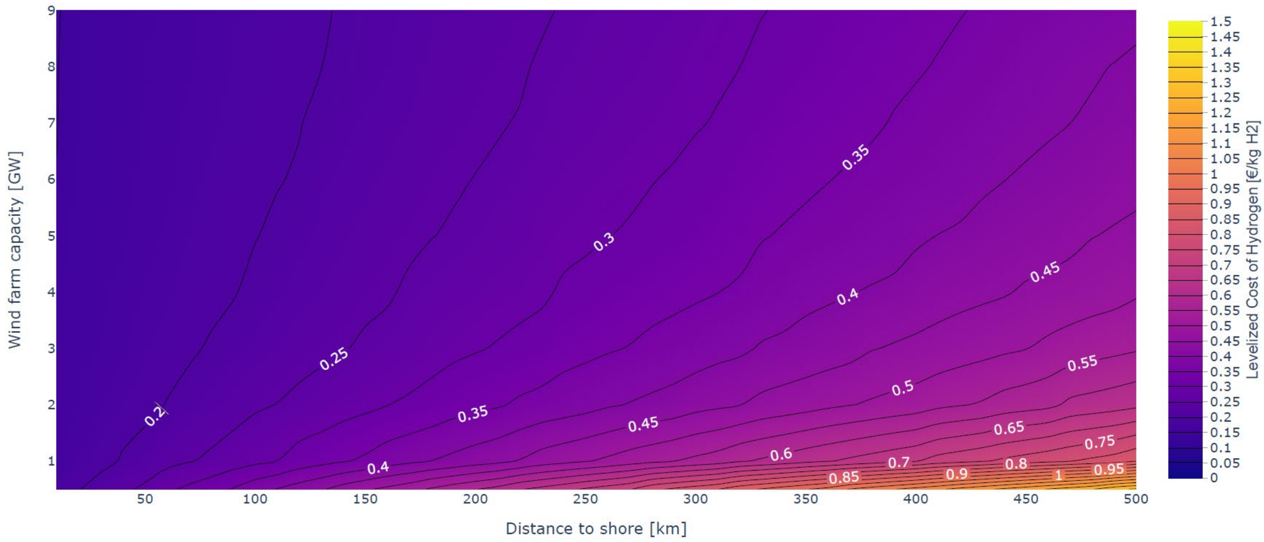


Figure 6-31: Levelized cost contour of Pipeline transport infra as a function of distance to shore and wind farm capacity (scaled colorbar for better visibility, max = 1.5 €/kg H2)

As can be seen from the plot, we observe quadratic cost contours instead of the near vertical cost contours that were visible for the HVAC and HVDC cases, which were a result of near linear scaling of the cost with increasing capacity due to the limited size of individual cables/substations. Furthermore, it can be observed that the increase of the levelized transport cost with increasing distance is much slower compared to HVAC, and slower compared to HVDC.

5.5.4 Final comparison

When comparing the electrical transmission options, the most cost-effective option is given by the shaded regions in Figure 6-32.

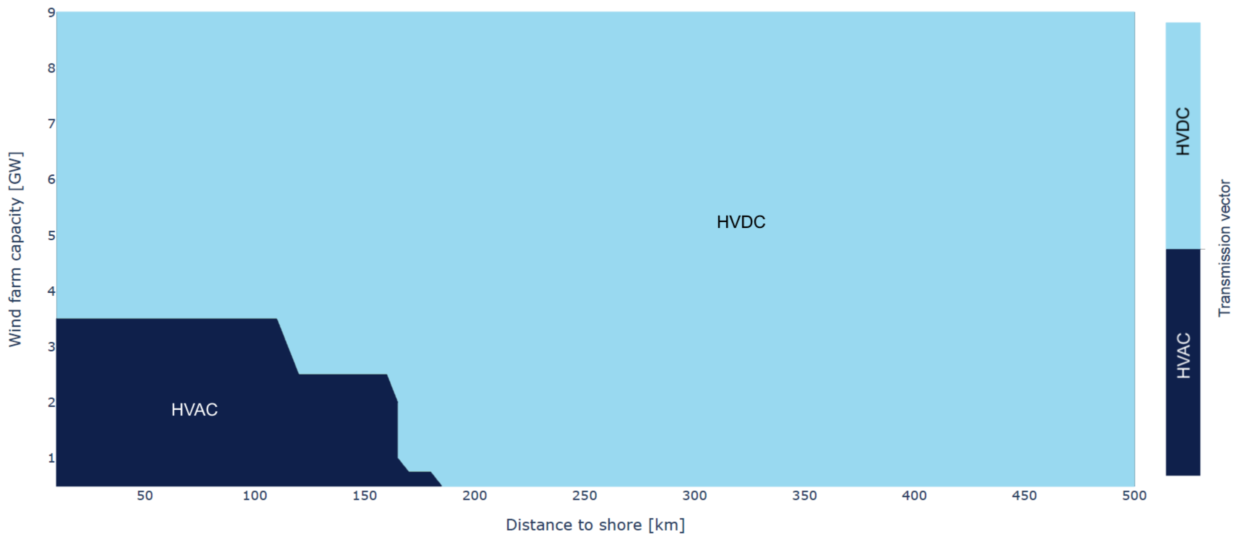


Figure 6-32: Most cost-effective electricity transmission vector (HVAC/HVDC)

The jumps in the line between HVAC and HVDC are caused by the granularity of the analysis, e.g. 10 km steps in the spatial domain and 0.5 GW steps in the wind farm capacity domain. In reality, the border will follow an inversely quadratic curve that is caused by the increasing efficiency loss of HVAC with increasing distance. This quadratic behavior is visible in **Figure 6-33**.

When comparing the electrical transmission options with the transport by hydrogen pipeline, it will turn out that pipeline transport will be the most cost-effective option for any combination of distance to shore and wind farm capacity in this analysis. This is illustrated in **Figure 6-33** (1.0 GW wind farm), Figure 6-34 (2.0 GW wind farm), and Figure 6-35 (8.0 GW wind farm).

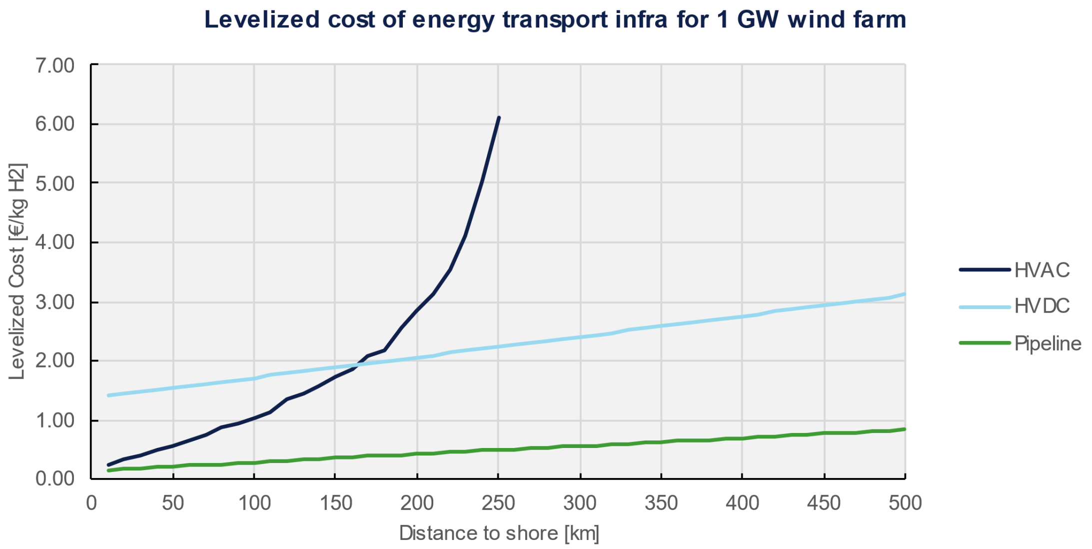


Figure 6-33: Most cost-effective energy transmission vector (HVAC/HVDC/Pipeline) for a 1.0 GW wind farm

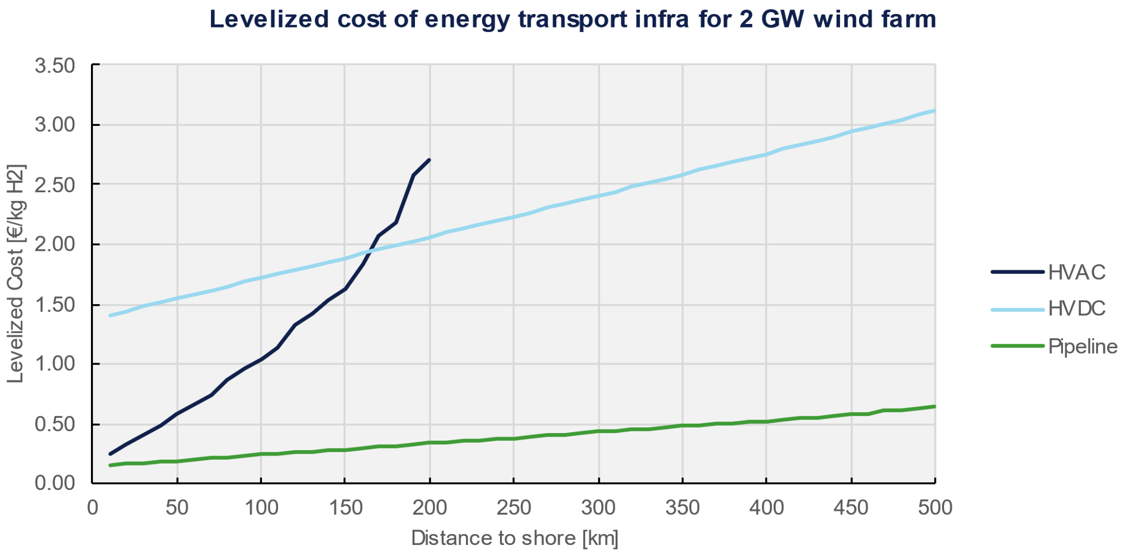


Figure 6-34: Most cost-effective energy transmission vector (HVAC/HVDC/Pipeline) for a 2.0 GW wind farm

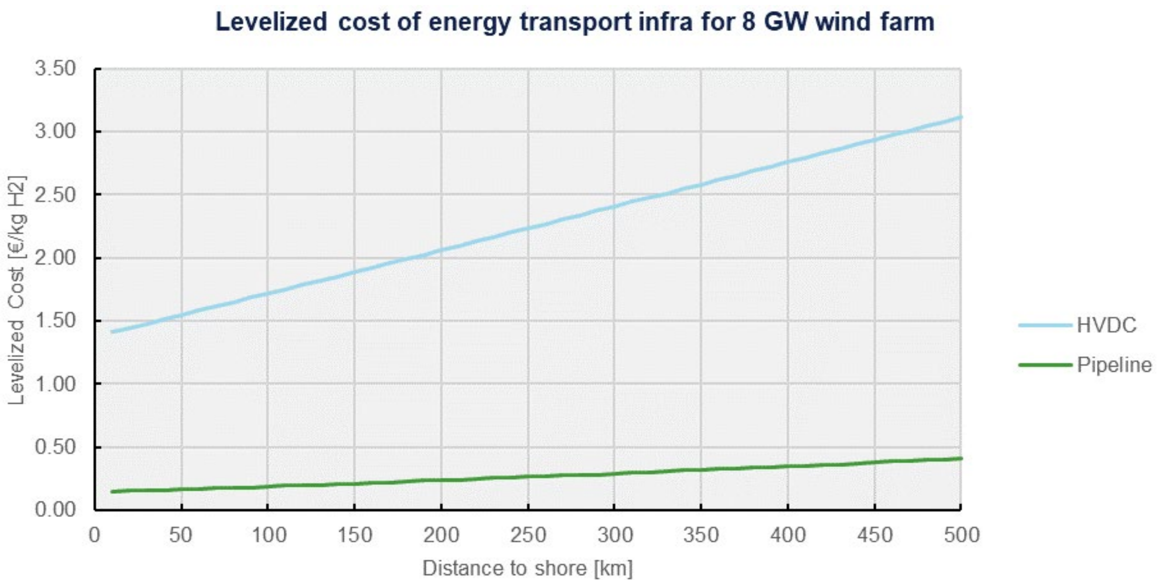


Figure 6-35: Most cost-effective energy transmission vector (HVDC/Pipeline) for an 8.0 GW wind farm

Caveats
This analysis only covers the (levelized) cost of the transport infrastructure, and therefore excludes the reality that installing and operating hydrogen production equipment offshore rather than onshore will be more expensive. Upon inclusion of these costs, DNV expects the cost-optimum to shift towards a situation where HVAC will be the most cost-effective transport option until 100 – 150 km from shore, based on earlier studies. Afterward, hydrogen pipelines will take over and will be more cost-effective than HVDC transport for any combination of distance to shore and wind farm capacity in this analysis.

6 GREEN HYDROGEN PRODUCTION POTENTIAL

India has set ambitious goals to become energy independent by 2047 and achieve net-zero emissions by 2070. To reach these goals, India is transitioning to clean energy sources, and green hydrogen is a key part of this transition. Green hydrogen is a clean and renewable fuel that can be used for a variety of purposes, including long-duration storage of renewable energy, replacement of fossil fuels in industry, and clean transportation.

Keeping net zero pledges in sight, the Government of India has launched the green hydrogen mission 2023 [16] with the following likely outcomes by 2030:

- Development of green hydrogen production capacity of at least 5 MMT (Million Metric Tonne) per annum with an associated renewable energy capacity addition of about 125 GW in the country
- Potential to reach 10 MMT per annum with the growth of export markets
- Over Rs. Eight lakh crore (8,000 billion INR) in total investments
- Creation of over Six lahks (0.6 million) jobs
- The cumulative reduction in fossil fuel imports over Rs. One lakh crore (1,000 billion)
- Abatement of nearly 50 MMT of annual greenhouse gas emissions

6.1 Hydrogen Demand in India

Based on NITI Aayog (Indian Government Think Tank) Report [17], India currently consumes around 6 million tonnes of grey hydrogen, which is basically hydrogen produced from fossil fuels. The majority of this hydrogen is used in industrial applications, such as refining, ammonia production, and methanol production. Currently, refining and ammonia production account for almost equal shares of hydrogen consumption, with methanol production accounting for a small share. Hydrogen demand can potentially grow more than fourfold between 2020 and 2050, amounting to around 29 million tonnes by 2050. To create a large demand for green hydrogen and scale up its production, the Government of India will mandate that designated consumers use a minimum share of green hydrogen or its derivative products, such as green ammonia and green methanol, as energy or feedstock. Driven by the low cost of renewables, India can emerge as an export hub for green hydrogen.

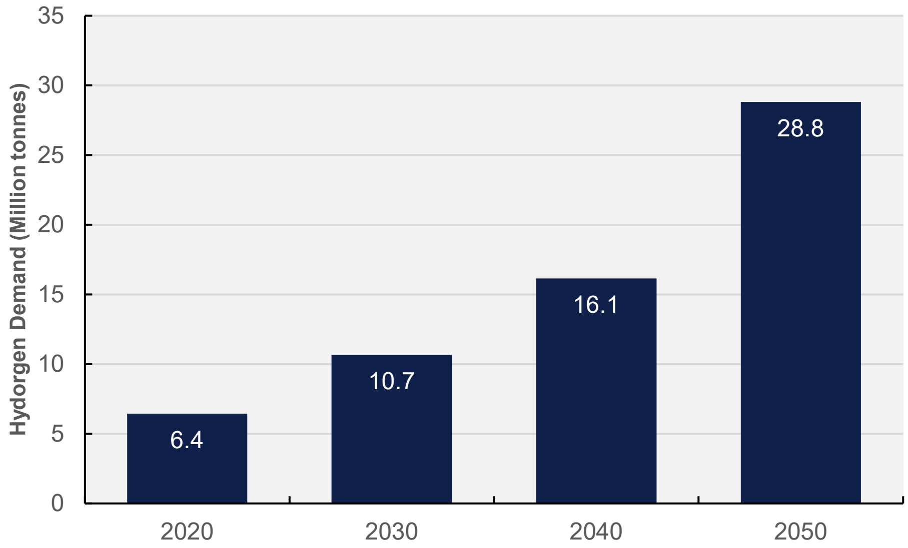


Figure 7-1 Hydrogen demand outlook of India [17]

If a major part of the hydrogen production is from renewables, offshore wind could play a major role due to its advantages like the absence of land-related issues, scaling possibilities, large-size wind farms, availability of wind farms, export through sea route, etc.

6.2 Green Hydrogen from Offshore Wind

This section describes the potential of green hydrogen production from 100 GW of offshore wind. For this exercise, DNV has used the India offshore wind potential estimated by ESMAP-IFC [18]Offshore Wind Development Program [19]. The potential areas were identified using the following constraint:

- Regions with annual average 100-meter height wind speeds of greater than 7 m/s are considered technically viable (for the current performance characteristics of offshore wind turbines)
- Fixed offshore wind is suitable for water depths of less than 50 m
- Floating wind farms are suited for water depths between 50 to 1,000 m
- Only regions less than 200 km from the shore are considered

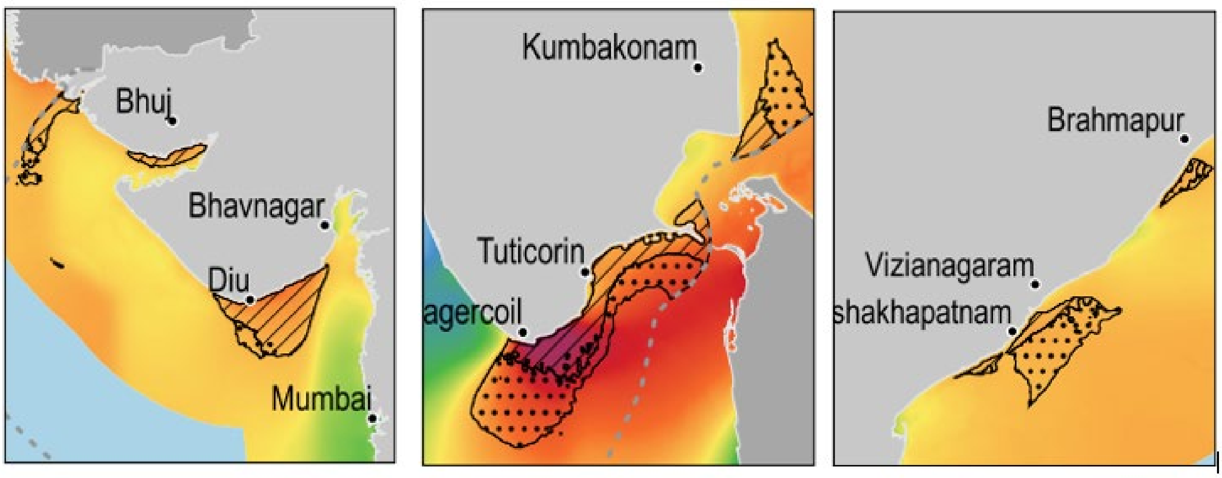


Figure 7-2 Offshore Wind Potential Areas in India

For the Tamil Nadu area, zones C, G and H were excluded due to intersecting areas demarcated by the Ministry of Defence. The same holds for Gujarat zone H. Table 7-1 lists the wind areas, their areas, the projected wind power density, foundation type, potential capacity, partial load factor and finally a high-level annual energy yield.

Table 7-1: Assumptions for total annual wind yield

Area	Zone	Area (km2)	Foundation	Potential Capacity (GW)	PLF (%)	Yield (GWh_e)
Gujarat	A	1,921	Bottom fixed	10	35%	30,660
	B	2,924	Bottom fixed	10	35%	30,660
	D	2,547	Bottom fixed	10	29%	25,404
	E	2,503	Bottom fixed	10	29%	25,404
	F	2,519	Bottom fixed	10	31%	27,156
Tamil Nadu	A	588	Bottom fixed	5	40%	17,520
	B	1,557	Bottom fixed	5	50%	21,900
	C	810	Bottom fixed	5	40%	17,520
	D	1,015	Bottom fixed	5	45%	19,710
	E	1,316	Bottom fixed	5	45%	19,710
	F	1,556	Bottom fixed	5	30%	13,140
	G	1,602	Bottom fixed	5	40%	17,520
Tamil Nadu	P6	1500	Floating	5	35%	15,330
Vizag G	P8	2000	Floating	10	35%	30,660
Total		24,358		100	35.65%	312,294

From the total yearly electricity yield of ~312,000 GWh (35.65% average partial load factor), we can calculate the potential hydrogen production. For this, we distinguish three scenarios which account for specific factors that can lead to a loss of energy in the value chain such as distance to shore (transport efficiency) and electrolysis efficiency.

Table 7-2: Assumptions for average wind-to-hydrogen value chain efficiency of selected zones

Scenario	Value chain efficiency (% HHV)
Low	60%
Base	68%
High	75%

These scenarios yield a hydrogen production potential for the 100 GW of offshore wind energy planned in India of 4.76 MT H2/yr (low) – 5.35 MT H2/yr (base) – 5.95 MT H2/yr (high) [8].

[8] 1 Mt = 1 million tonnes = 1 billion kilogrammes

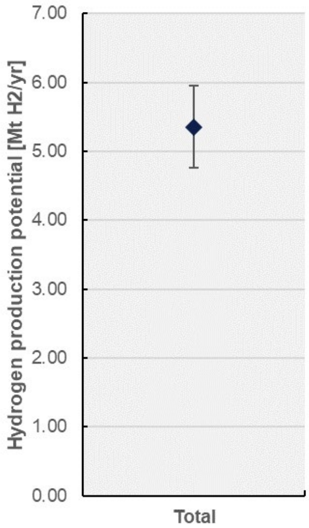


Figure 7-3: Total hydrogen production potential from 100 GW of offshore wind

Even with a base estimate of 5.35 million metric tons (MMT), the National Green Hydrogen Mission's target of 5 million metric tons (MMT) can easily be achieved. Moreover, if we also account for the ambitious goal of exporting hydrogen via the sea route, the additional target of 5 MMT for exports can be met. It's worth noting that the aforementioned capacity projection of 5.35 MMT assumes a 100 gigawatt (GW) offshore potential. However, the actual offshore wind potential exceeds this figure. According to the ESMAP-IFC's Offshore Wind Development Program, India's estimated offshore wind potential stands at 174 GW (91 GW fixed and 83 GW floating). Taking this larger potential into consideration, hydrogen production could reach a staggering 10 MMT per annum. Furthermore, the potential for offshore wind energy is dynamic and expected to grow significantly as technology, particularly in floating wind, matures. Overall, the immense scale and possibilities of green hydrogen production from offshore wind make it an opportunity that cannot be overlooked. Therefore, an integrated policy to harness this potential is essential.

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APPENDIX A: TECHNO-ECONOMIC MODEL

The model is the central point where all inputs and expertise are converged together to produce the results. The existing DNV wind-to-hydrogen models are built in Python and integrated into DNVs proprietary software Renewables. Architect. It distinguishes between general inputs, case-specific inputs, and technology inputs which are integrated in a yearly based time series, representing the project lifetime. This time series contains the costs and yield for each year from which the results like LCOE and LCOH are calculated. The model is used to calculate these results for multiple cases, to compare between cases, to make optimisations, and to analyse the sensitivities. A general overview of the model is depicted in the figure below.

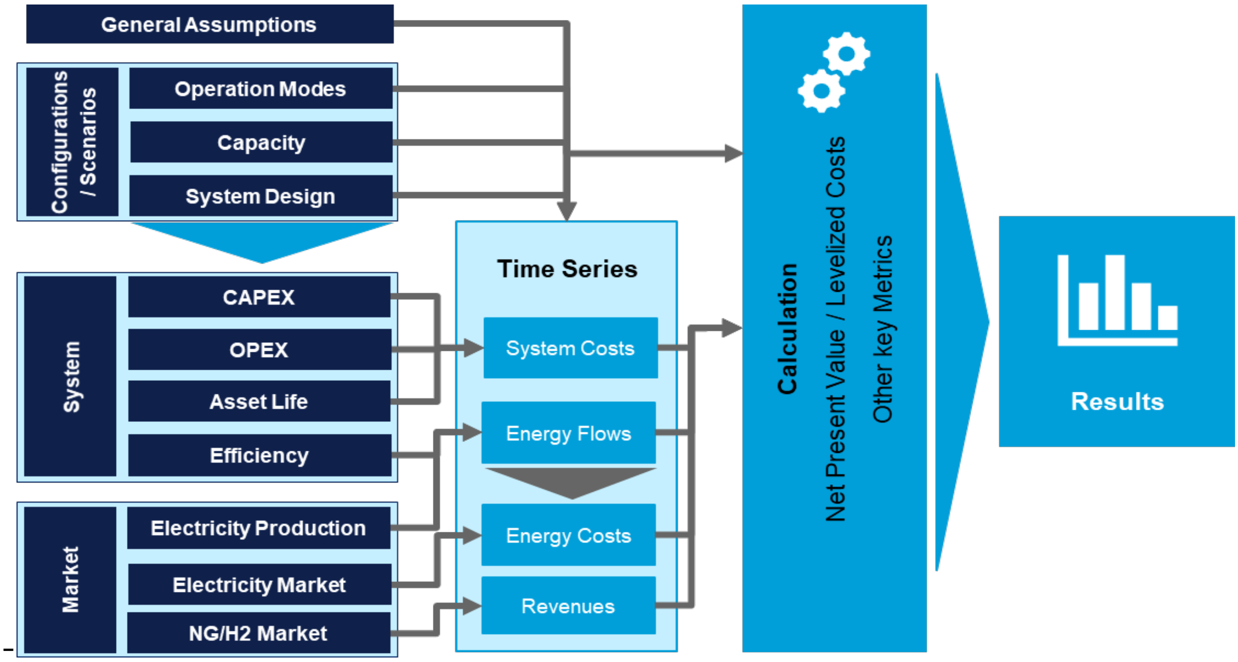


Figure 8-1 - Illustrative description of DNV's feasibility model used in this project

A.1 Techno-economic model architecture

A.1.1 Main input dashboard

The model contains a "Scenario Builder" to build different cases and select different inputs. The general inputs like WACC (discount rate), inflation, assessment period, and construction phasing can be selected. A maximum of 10 phases is possible where for each phase a selection can be made of the start year of the construction, the end year of the construction, and the number of turbines that will be installed. The year after the construction has finished, the operation will start. It should be noted that the correct phasing should include a realistic view on construction duration and one phase should not exceed one of the wind farm plot areas.

The same scenario builder also contains a list of equipment that should be selected to include in each case. For example, a selection can be made between a pressurized alkaline electrolyser and a PEM electrolyser. Multiple cases can be built simultaneously in separate batch runs.

A.1.2 Energy & cost calculations

The calculations are performed in separate modules; the calculation of the required capacities for each technology, the CAPEX, the OPEX and the energy/hydrogen yields. The CAPEX, OPEX and energy yields are calculated on a yearly basis and are calculated separately for each phase. The calculations are either directly based on the inputs or via special formulas that were included in the technology input database.

The calculations are further supported by a set of conversion factors -this assessment uses the higher heating value (HHV) [9] of hydrogen- and the following rules:

- For some technologies, a maximum allowable capacity is assumed
    - An HVAC substation can have a maximum capacity of 1,000 MW
    - An HVAC cable can have a maximum capacity of 350 MW
    - The electrolyser has scaling advantages until 100 MW. After that costs scale linearly.
    - A hydrogen production platform can carry up to 800 MW of electrolysers plus auxiliary equipment (although in this assessment due to the total project size, 500 MW platforms are utilized).
    - A hydrogen compressor can compress up to 800,000 Nm3 H_2/hr
- Efficiency degradation (mainly for the electrolyser stacks) is calculated on a yearly basis. The efficiency at the end of the year is applied to the energy yield of that whole year. The stacks are assumed to be replaced after a fixed number of full load hours and are replaced all at once for one phase. After replacement, the efficiency is restored to the beginning of life again.

Additional calculations

Some calculations are performed outside of the model or are integrated as separate modules:

- The costs of the foundations, turbines, array cabling, offshore HVAC substation, export cables and onshore HVAC substation or offshore HVDC substation, export cables and onshore HVDC substation (in both cases including a small grid connection and step down to the hydrogen plant input voltage) were calculated using industry-leading models in DNV's proprietary software tool Turbine. Architect.

[9] Higher heating value is also referred to as the gross calorific value. During combustion of hydrogen rich fuels water is released by combining hydrogen and oxygen. This subsequently evaporates which consumes some of the energy which is then not available anymore to "do work". The lower heating value, net calorific value, corrects for this "loss" and is therefore lower. The higher and lower heating value of hydrogen are 142 and 120 MJ/kg respectively. Throughout this assessment the higher heating value has been used consequently.

A.1.3 General assumptions – Tamil Nadu

Table 8-1 below features general assumptions that were taken as inputs to the techno-economic model.

Table 8-1 - General assumption for India, Tamil Nadu wind farm – Levelized Cost of Hydrogen case study

Input	Value	Comment
WACC/Discount rate (real)	10.0% per year	DNV expert assumption
Base year	2023	All costs are made Net Present to 2023
Assessment period	25 years	
Begin construction	2029	
Begin operation	2030	
Water depth	29 m	
Number of turbines	50	
Turbine rating	20 MW	
Total installed power	1,000 MW	
Turbine hub height	155 m	
Turbine rotor diameter	265 m	
Lifetime Net energy output	4,109 GWh/yr	
Net capacity factor	46.3%	
Electrolyser sizing	100% of wind capacity	Can be optimized in combination with BESS or grid interaction in future studies.
Distance to shore export route offshore	15 km	Assumption based on the indicative routing
Distance export route onshore	12 km	Assumption based on the indicative routing
Distance to nearest construction port	111 km	
Distance to the nearest maintenance port	20 km	
Export pipeline offshore outer diameter	10.8”	DNV expert assumption based on expected flow
Export pipeline onshore outer diameter	10.8”	DNV expert assumption based on expected flow
Transport cost	12.0% of CAPEX	DNV expert assumption based on transport modeling from Europe to India
Project cost*	17.0% of CAPEX	DNV expert assumption based on expected learning in wind farm project development
Decommissioning cost – wind farm	3.3% of CAPEX	DNV expert assumption based on expected learning in wind farm decommissioning
Decommissioning cost – hydrogen plant	5.0% of CAPEX	DNV expert assumption based on values from chemical industry decommissioning

*Project cost includes estimates for soft costs such as project cost (package management 5% of CAPEX), insurance & legal costs (2% of CAPEX), and contingency (10% of CAPEX).

A.1.4 Technology input database – Tamil Nadu

The technology inputs are collected in a database, comprising the relevant CAPEX figures, descriptions of how to scale and future developments, OPEX figures (fixed and variable), efficiency, degradation, lifetime, and information on weight and dimensions. In this study, all inputs and considerations to the database are collected from discipline experts. Not all values in the table below are fixed inputs, rather they are normalized or frozen to reflect the Tamil Nadu wind-to-hydrogen project and as such should not be directly applied to reflect sites with different conditions.

Table 8-2 - Technology input database for Tamil Nadu case study

Technology	*Material Cost*	*Unit*	*Installation Cost*	*Yearly OPEX*
			% of CAPEX	*% of CAPEX*
20 MW Turbine foundation – jacket 29 m water depth	353,800	€/MW	Included	2.0%
20 MW Turbine (66 kV) bottom fixed – 29 m water depth	1,282,800	€/MW	Included	2.0%
Added turbine structure (to carry 20 MW electrolyser + BoP + WT per turbine)	24,700	€/MW	Included	Included in turbine FOM
Array Cables (66 kV)	77,000	€/MW	Included	2.5%
Array pipelines for 1 turbine per electrolyser	78,800	€/MW	Included	1.0%
Offshore AC substation (66-220 kV) bottom fixed	78,800	€/MW	Included	1.0%
Onshore AC substation (220 - 66 kV)	13,800	€/MW	Included	1.0%
220 kV AC export cable offshore	73,500	€/MW	Included	2.5%
220 kV AC export cable onshore	8,600	€//MW	Included	2.5%
Transformer station 66/33 kV (incl. trafo, switchgear, and reactive power compensation)	44,700	€/MW	Included	1.0%
Alkaline stacks	200,000*	€/MW (electrolyser)	70%	1.5%
Alkaline BoP (33 kV in)	485,000*	€/MW (electrolyser)	70%	1.5%
PEM stacks	430,000*	€/MW (electrolyser)	70%	1.5%
PEM BoP (33 kV in)	535,000*	€/MW (electrolyser)	70%	1.5%
Thermal desalination water treatment	15,000	€/MW (electrolyser)	Included	2.0%
H2 Compressor (30 > 80 bar)	Scaling [10]	€/MW (electrolyser)	100% (onshore) 150% (offshore)	4.0%
Integrated concept marinization	4,700	€/MW (electrolyser)	Included	5,200 €/MW/yr (electrolyser)
Platform concept marinization	Included in platform installation	€/MW (electrolyser)	Included in platform installation	175 €/MW/yr (electrolyser)
Hydrogen production platform bottom fixed – 29 m water depth	67,300	€/MW (electrolyser)	Included	0.5%
Hydrogen export pipeline offshore (10.8")	860,000	€/km	Included	1.0%
Hydrogen export pipeline onshore (10.8")	573,300	€/km	Included	1.0%

* These values represent a 1 MW system, in the model this is scaled up to the respective hydrogen plant scale of ~1,000 MW (onshore centralized), ~500 MW (offshore platform), or 20 MW (offshore decentralized hydrogen-turbine), see also the section titled Electrolysers in Appendix A.

[10] H2 compressor CAPEX (€) = 22,000 * (0.02* capacity in Nm³/h)^0.6089

Table 8-3 – Electrolyzer KPIs for Tamil Nadu case study

ELX topology	Pressurized Alkaline	PEM	Unit
System CAPEX (1 MW)	685	965	EUR/kW
Stack (replacement) CAPEX (1 MW)	200	430	EUR/kW
BoP CAPEX (1 MW)	485	535	EUR/kW
Stack efficiency	82.6	79.2	% (HHV)
BoP efficiency	93.8	95.4	% (HHV)
Stack efficiency degradation	1.053E-06	1.333E-06	%/hr
System Lifetime	100,000	75,000	Full load hours
Weight	8,500	7,000	kg/MW
Space claim	35	30	m2/MW

Hydrogen export pipeline

Based on a maximum instantaneous flow of hydrogen of ~21 ton H2/hr at the pressure of 80 bar, to be transported over a distance of 27 km (15 km offshore + 12 km onshore), DNV experts have calculated a cost-optimal sizing for the pipelines as shown in the table below.

Table 8-4 – Tamil Nadu hydrogen export pipeline characteristics

Variable	Value	Unit
Internal diameter	250.7	mm
External diameter	273.0 (10.8)	mm (inch)
Wall thickness	11.13	mm
Wall roughness	0.05	mm
Design pressure (+tolerance)	80 (+5)	bara
Inlet pressure	80	bara
Outlet pressure	58	bara
Operating temperature	20	°C

A.1.5 General assumptions – Gujarat

Table 8-5 below features general assumptions that were taken as inputs to the techno-economic model.

Table 8-5 - General assumption for India, Gujarat wind farm – Levelized Cost of Hydrogen case study

Input	Value	Comment
WACC/Discount rate (real)	10.0% per year	DNV expert assumption
Base year	2023	All costs are made Net Present to 2023
Assessment period	25 years	
Begin construction	2029	
Begin operation	2030	
Water depth	15 m	
Number of turbines	50	
Turbine rating	20 MW	
Total installed power	1,000 MW	
Turbine hub height	155 m	
Turbine rotor diameter	265 m	
Lifetime Net energy output	3,012 GWh/yr	
Net capacity factor	33.7%	
Electrolyser sizing	100% of wind capacity	Can be optimized in combination with BESS or grid interaction in future studies.
Distance to shore export route offshore	38 km	Assumption based on the indicative routing
Distance export route onshore	12 km	Assumption based on the indicative routing
Distance to nearest construction port	35 km	
Distance to the nearest maintenance port	35 km	
Export pipeline offshore outer diameter	10.8”	DNV expert assumption based on expected flow
Export pipeline onshore outer diameter	10.8”	DNV expert assumption based on expected flow
Transport cost	12.0% of CAPEX	DNV expert assumption based on transport modelling from Europe to India
Project cost*	17.0% of CAPEX	DNV expert assumption based on expected learning in wind farm project development
Decommissioning cost – wind farm	3.3% of CAPEX	DNV expert assumption based on expected learning in wind farm decommissioning
Decommissioning cost – hydrogen plant	5.0% of CAPEX	DNV expert assumption based on values from chemical industry decommissioning

*Project cost includes estimates for soft costs such as project cost (package management 5% of CAPEX), insurance & legal costs (2% of CAPEX), and contingency (10% of CAPEX).

A.1.6 Technology input database – Gujarat

The technology inputs are collected in a database, comprising the relevant CAPEX figures, descriptions of how to scale and future developments, OPEX figures (fixed and variable), efficiency, degradation, lifetime and information on weight and dimensions. In this study, all inputs and considerations to the database are collected from discipline experts. Not all values in the table below are fixed inputs, rather they are normalized or frozen to reflect the Gujarat wind-to-hydrogen project and as such should not be directly applied to reflect sites with different conditions.

Table 8-6 - Technology input database for Gujarat case study

Technology	*Material Cost*	*Unit*	*Installation Cost*	*Yearly OPEX*
			% of CAPEX	*% of CAPEX*
20 MW Turbine foundation – jacket 15 m water depth	312,300	€/MW	Included	2.0%
20 MW Turbine (66 kV) bottom fixed – 15 m water depth	1,276,700	€/MW	Included	2.0%
Added turbine structure (to carry 20 MW electrolyser + BoP + WT per turbine)	24,700	€/MW	Included	Included in turbine FOM
Array Cables (66 kV)	77,000	€/MW	Included	2.5%
Array pipelines for 1 turbine per electrolyser	78,800	€/MW	Included	1.0%
Offshore AC substation (66-220 kV) bottom fixed	78,800	€/MW	Included	1.0%
Onshore AC substation (220 - 66 kV)	13,800	€/MW	Included	1.0%
220 kV AC export cable offshore	186,100	€/MW	Included	2.5%
220 kV AC export cable onshore	21,100	€//MW	Included	2.5%
Transformer station 66/33 kV (incl. trafo, switchgear and reactive power compensation)	44,700	€/MW	Included	1.0%
Alkaline stacks	200,000*	€/MW (electrolyser)	70%	1.5%
Alkaline BoP (33 kV in)	485,000*	€/MW (electrolyser)	70%	1.5%
PEM stacks	430,000*	€/MW (electrolyser)	70%	1.5%
PEM BoP (33 kV in)	570,000*	€/MW (electrolyser)	70%	1.5%
Thermal desalination water treatment	15,000	€/MW (electrolyser)	Included	2.0%
H2 Compressor (30 > 80 bar)	Scaling [11]	€/MW (electrolyser)	100% (onshore) 150% (offshore)	4.0%
Integrated concept marinization	4,700	€/MW (electrolyser)	Included	5,200 €/MW/yr (electrolyser)
Platform concept marinization	Included in platform installation	€/MW (electrolyser)	Included in platform installation	175 €/MW/yr (electrolyser)
Hydrogen production platform bottom fixed – 15 m water depth	52,000	€/MW (electrolyser)	Included	0.5%
Hydrogen export pipeline offshore (10.8")	860,000	€/km	Included	1.0%
Hydrogen export pipeline onshore (10.8")	573,300	€/km	Included	1.0%

* These values represent a 1 MW system, in the model this is scaled up to the respective hydrogen plant scale of ~1,000 MW (onshore centralized), ~500 MW (offshore platform), or 20 MW (offshore decentralized hydrogen-turbine), see also the section titled Electrolysers in Appendix A.

[11] H2 compressor CAPEX (€) = 22,000 * (0.02* capacity in Nm³/h)^0.6089

Table 8-7 – Electrolyzer KPIs for Gujarat case study

ELX topology	Pressurized Alkaline	PEM	Unit
System CAPEX (1 MW)	685	965	EUR/kW
Stack (replacement) CAPEX (1 MW)	200	430	EUR/kW
BoP CAPEX (1 MW)	485	535	EUR/kW
Stack efficiency	82.6	79.2	% (HHV)
BoP efficiency	93.8	95.4	% (HHV)
Stack efficiency degradation	1.053E-06	1.333E-06	%/hr
System Lifetime	100,000	75,000	Full load hours
Weight	8,500	7,000	kg/MW
Space claim	35	30	m2/MW

Hydrogen export pipeline

Based on a maximum instantaneous flow of hydrogen of ~21 ton H2/hr at the pressure of 80 bar, to be transported over a distance of 50 km (38 km offshore + 12 km onshore), DNV experts have calculated a cost-optimal sizing for the pipelines as shown in the table below.

Table 8-8 – Gujarat hydrogen export pipeline characteristics

Variable	Value	Unit
Internal diameter	250.7	mm
External diameter	273.0 (10.8)	mm (inch)
Wall thickness	11.13	mm
Wall roughness	0.05	mm
Design pressure (+tolerance)	80 (+5)	bara
Inlet pressure	80	bara
Outlet pressure	39	bara
Operating temperature	20	°C

APPENDIX B: TECHNOLOGY BACKGROUND

This chapter features detailed schematics of the components present in the three offshore-wind-to-hydrogen topologies presented in chapter 4.1, given in section B.1. Then, section B.2 features an in-depth discussion on electrolysis technology. Furthermore, section B.3 discusses the sub-structures that can be used for offshore hydrogen production platforms.

B.1 Topology schematics

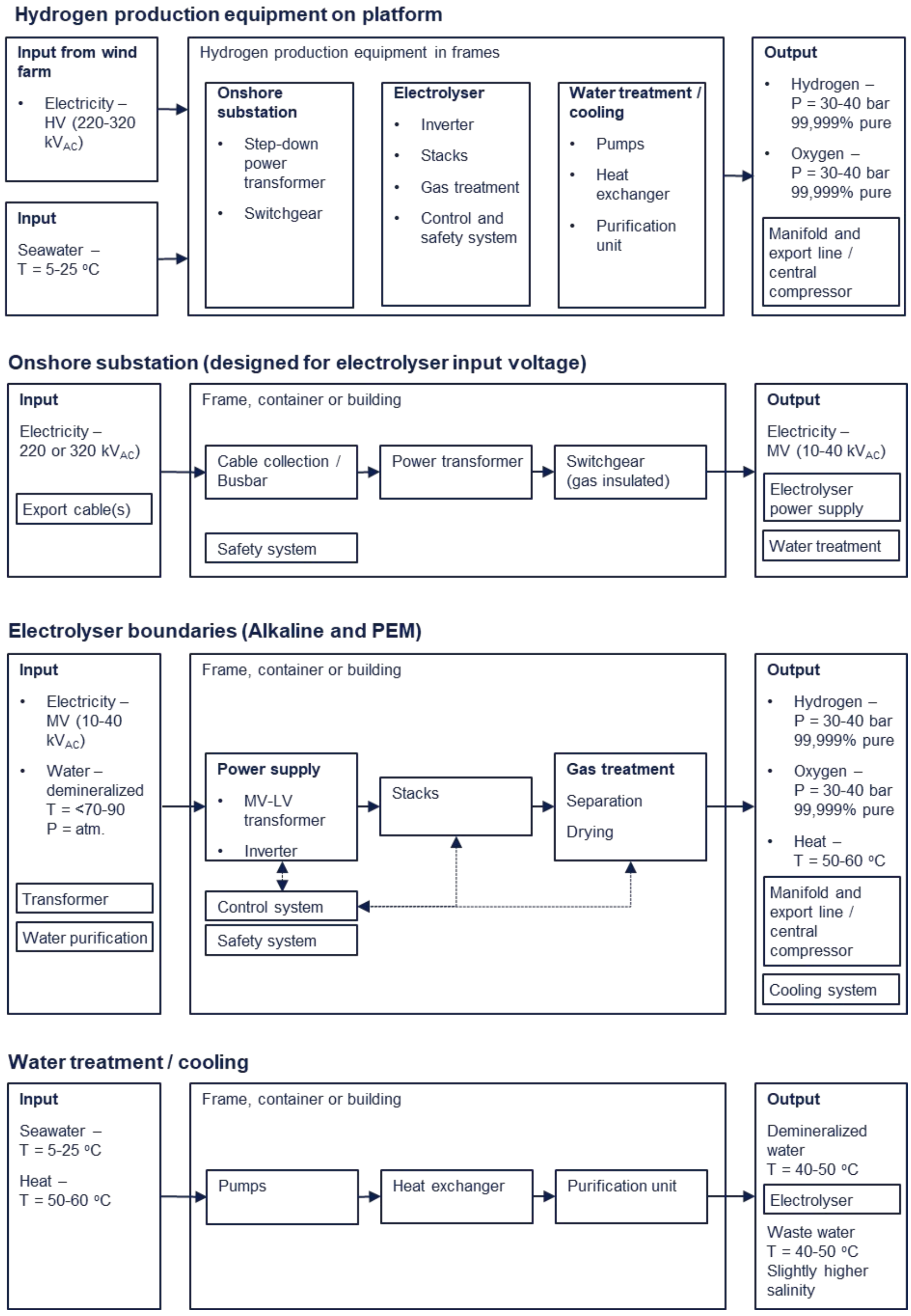


Figure 8-2: Schematic representation of components in the Onshore Centralized topology (#1).

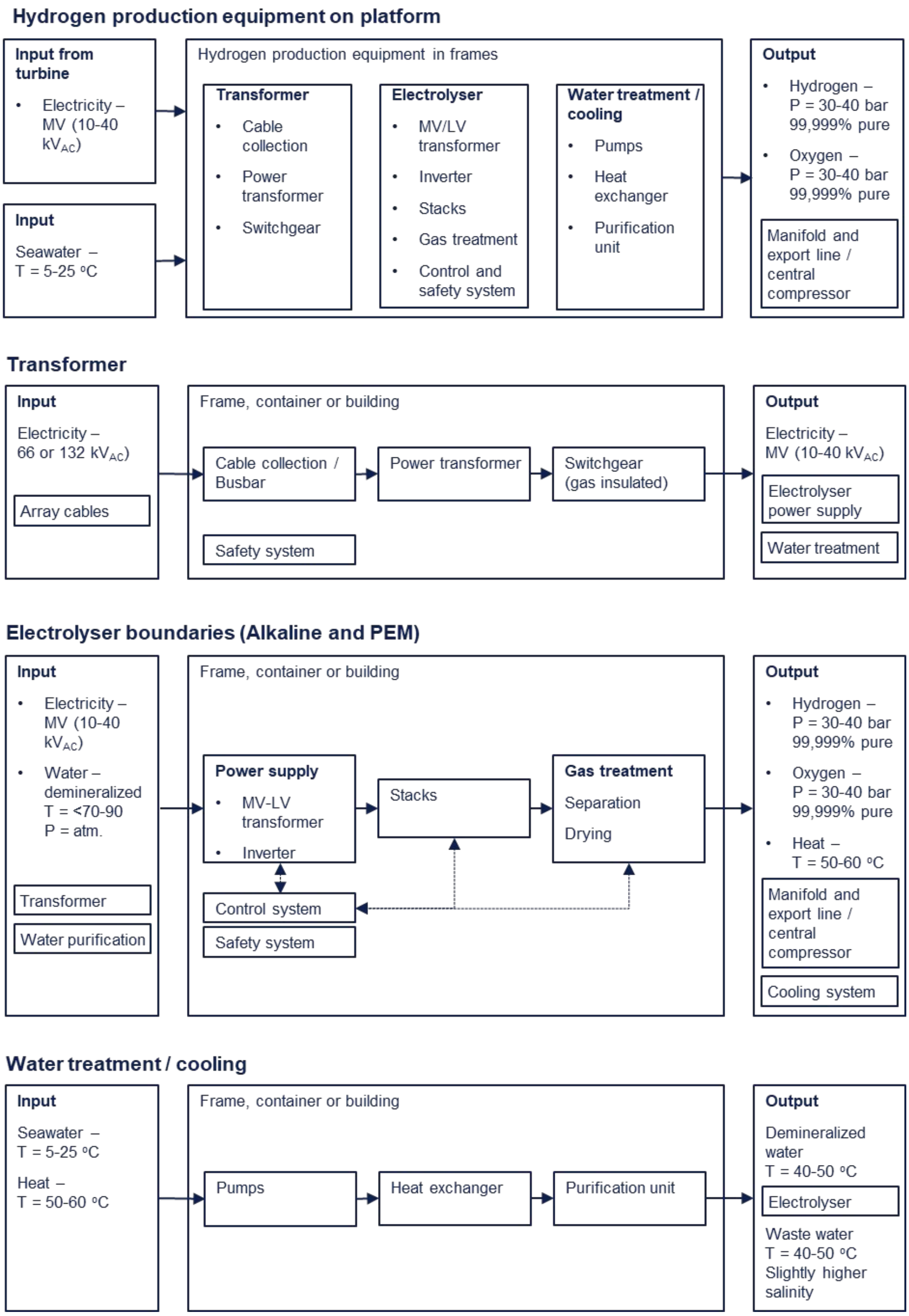


Figure 8-3: Schematic representation of components in the Offshore Centralized topology (#2). Hydrogen production on an offshore hydrogen production platform.

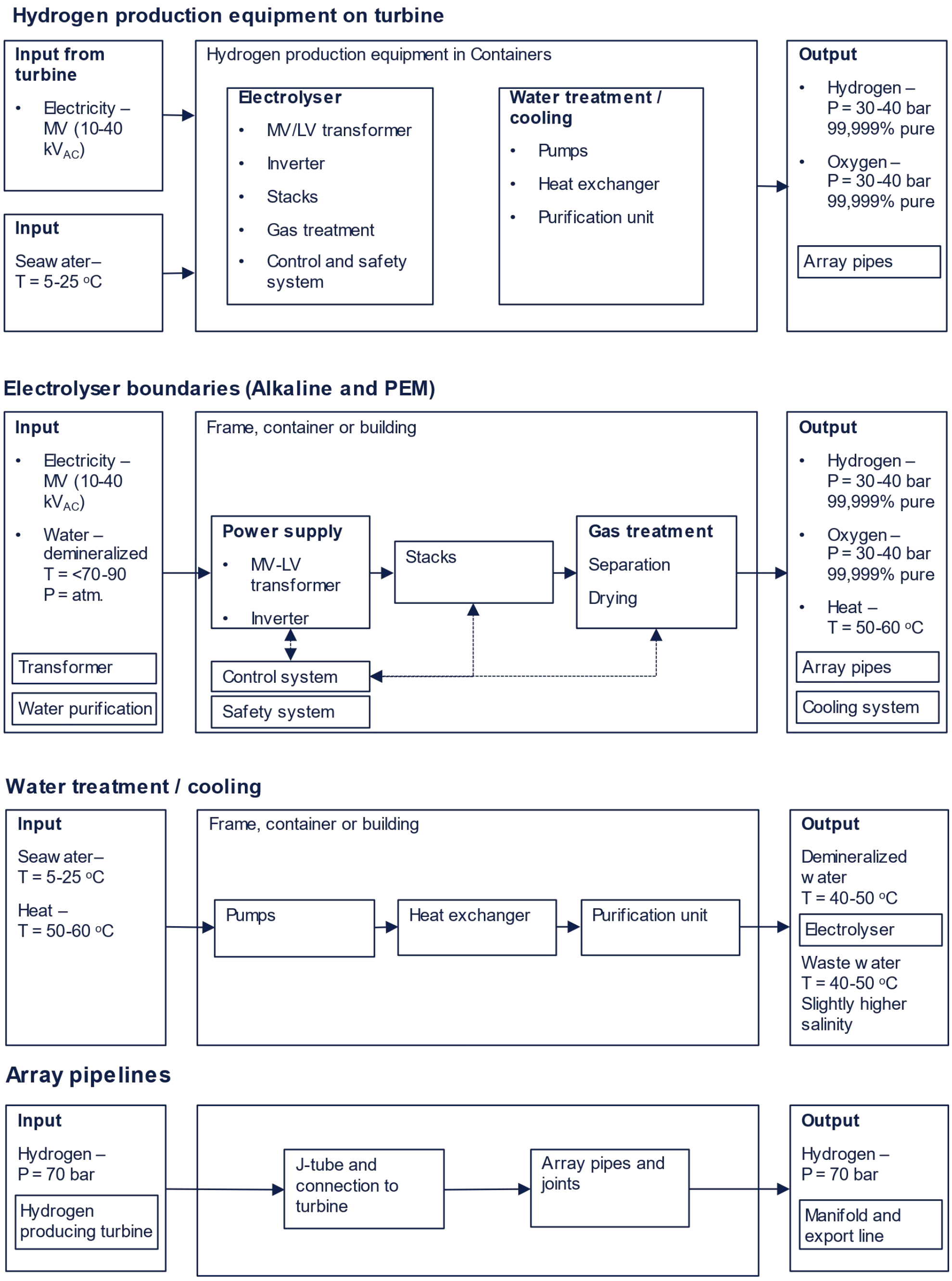


Figure 8-4: Schematic representation of components in the Offshore Decentralized topology (#3). Hydrogen production integrated at the turbine feeds into array pipelines.

B.2 Electrolysers

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

A schematic representation of an electrolyser system is given in Figure 8-5.

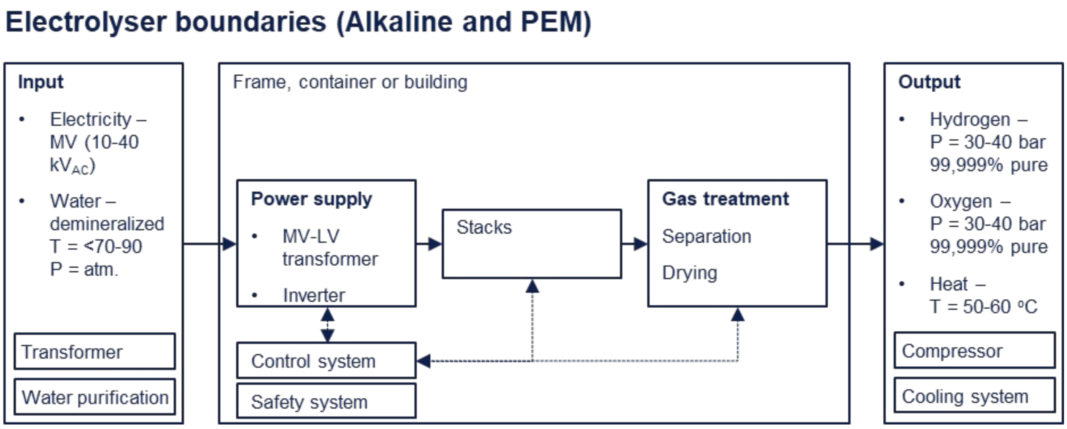


Figure 8-5: Schematic representation of electrolyser system

The current state of the technology & development expectation

Electrolysers are currently in the scale of multiple MW and manufacturers are getting ready to apply modular systems (0.1 – 25 MW each) that allow for the scale-up of complete plants in the range of hundreds of MW to GWs. GW scale plants are expected to be technically feasible towards 2030 but a successful development of the current global project pipeline (consisting of hundreds of MW plants) is key.

While scale is one important aspect of technical feasibility, the offshore application is another aspect. The current focus is largely on electrolyser development for large-scale onshore applications, but offshore application is increasingly being explored. The offshore application requires a direct coupling to renewable energy and therefore electrolysers should feature a rapid response time, minimized footprint and weight, and should have minimized maintenance requirements based on limited interventions. Currently only pressurized alkaline and PEM can meet these requirements and even with those technologies, further development is needed. Anion Exchange Membrane (AEM) could be another potential technology but is currently immature and its future is still uncertain. In this section, we therefore only focus on pressurized alkaline and PEM.

In general, the development for both onshore and offshore applications is heading in the right direction, but for offshore development, this adds additional challenges and research & development need. Offshore application of electrolysis can be technically feasible by 2030 but development and pilot projects should start soon.

B.2.1 Offshore application

For offshore applications, electrolysis systems should be:

1. Capable of handling rapid intermittent loads from the turbine, with stable operating conditions (*very important*)
2. Having minimal maintenance requirements (*important*)
3. Having a minimal footprint and weight (*important*)
4. Capable of handling/mitigating impurities resulting from sea water (*not very important*)

Other decisive factors that could influence the choice of electrolysis technology.

- TRL
- Concept development timelines
- Cost

Below, the four criteria outlined above are analysed in more detail.

1. The electrolyser should be capable of handling intermittent power supply from the wind turbines (*very important*)

- Atmospheric alkaline has a larger footprint and is less capable of responding to variable energy input than pressurized alkaline or PEM. As such, it will likely not be the preferred choice of technology for offshore hydrogen production.
- Pressurized alkaline and PEM are capable of responding to variable energy input and have relatively small footprints.
- Solid Oxide Electrolysis (SOE) is not expected to be technically feasible. Solid Oxide requires an external source of heat which is not available offshore. It should in theory be possible to operate SOE flexibly, but this is energetically unfavourable given the fact that the system needs to be kept on a hot standby at extremely high operating temperatures (700-900 ^oC).
- Anion Exchange (AEM) is very similar to PEM and will likely be capable of handling fluctuations.

2. Offshore maintenance is remote and therefore expensive. Maintenance should be kept to a minimum (*important*)

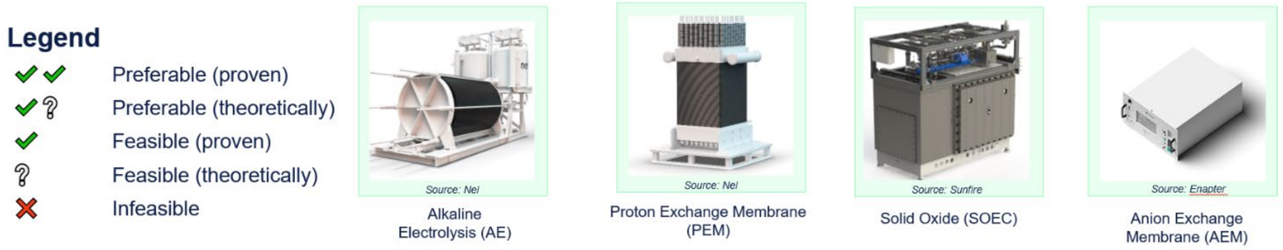
- This is a development that will need to happen for all electrolyser technologies but the more established technologies will go through this development earlier (pressurized alkaline and PEM). It is unclear if there are advantages or disadvantages between these two technologies in terms of maintenance.
- Pressurized alkaline developers indicate it is feasible to have no electrolyte exchange throughout the stack lifetime.
- The focus of Solid Oxide and AEM is first to improve lifetime and reliability before the development towards offshore application will start.

3. Weight and area are also relevant for offshore application (*important*)

- Currently both Pressurized alkaline and PEM fall in the same range. It is therefore not clear which will prove to be more beneficial.
- Given the novelty of commercial SOE and AEM systems, little information is available but it is expected that AEM will be similar to PEM.

4. Capable of handling/mitigating impurities from resulting from sea water (*not very important*)

- The industry standard to circumvent electrolyzer degradations, and to increase the guaranteed electrolyzer lifetime, has been to purify feed water to meet stringent requirements (see next chapter). This decision is mainly driven by the relatively low CAPEX, OPEX and energy requirement of water purification systems in relation to renewables and hydrogen production equipment.



	AAE	PAE	PEM	SOEC	AEM
Intermittency / op. cond.	✗	✓	✓	✗	?
Maintenance	?	?	?	?	✓?
Footprint / weight	✗	✓	✓✓	-	?
Impure water feed	✗	✗	✗	?	✓?

Increasing TRL

Figure 8-6: Summary of electrolysis technology selection for offshore application

B.2.2 Cost

Based on a large set of public data and vendor data, the data points in the figure below (Figure 8-7) have been corrected for size and represent a 1 MW system. For larger systems, scaling formulas should be applied which are further elaborated below. A fit and uncertainty are included in the figure and are based on the data points. These considered system costs which include both stack (typically 30% – 50% of the costs) and balance of plant (typically 50% – 70% of the costs. For some sources, there is uncertainty on the limits for the balance of the plant and could include items such as compressors or civil works/containers. In addition, there is much uncertainty around the cost due to the low maturity of the market and the uncertainty is increasing towards the future. It is expected that Alkaline and PEM will move closer to each other and could reach an equal cost level. Nonetheless, both technologies will see a large cost reduction where costs could be half of the current levels by 2050.

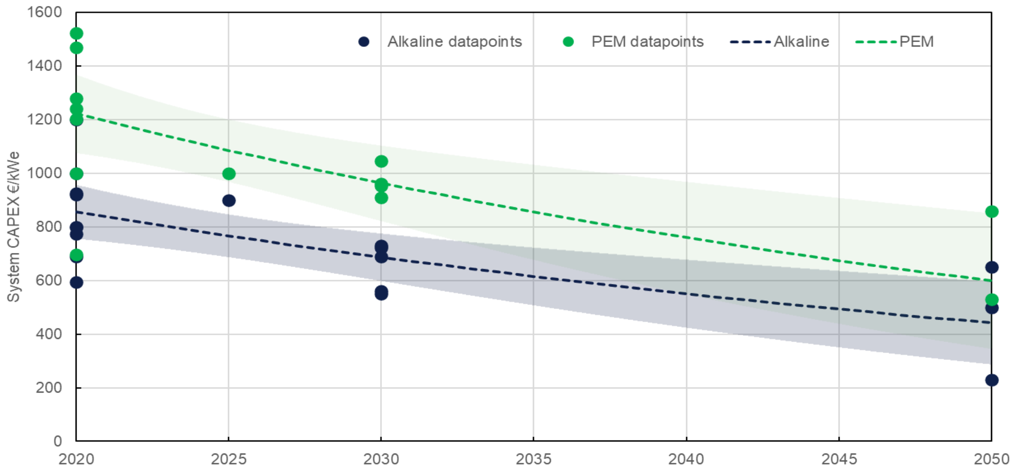


Figure 8-7 System CAPEX development of Alkaline and PEM for 1 MW reference.

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

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

Cost for Offshore application (Marinization)

To give some detail about making electrolysers offshore ready (often called marinization) please find this table (Sheet 2) with cost estimates for the different topologies. These costs have to be added to the onshore electrolyser costs to reflect the offshore situation.

Table 8-9: High-level cost for making electrolyzers offshore ready (marinization)

Technology	Type	Materia l Cost	Unit	Installation Cost	OPEX
Island concept	Marinizatio n	1,500	€/MW	shipping and installation of containers roughly results in 1,500 €/MW	110 €/MW/y
Platform concept	Marinizatio n			Already included in platform topside installation	175 €/MW/y
Integrated concept	Marinizatio n	4,500	€/MW	shipping and installation of containers roughly results in 4,500 €/MW	5,200 €/MW/y

B.2.3 Performance

As the electrolyser technologies mature, performance will also improve. The main performance aspects are power consumption and the lifetime of the stack. Figure 8-8 and Figure 8-9 below provide a fit to data points from literature and vendors for both the power consumption and stack lifetime. The power consumption is provided as the electric power consumption in kWh per Nm^3 of hydrogen produced. The figure again comprises the whole system.

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

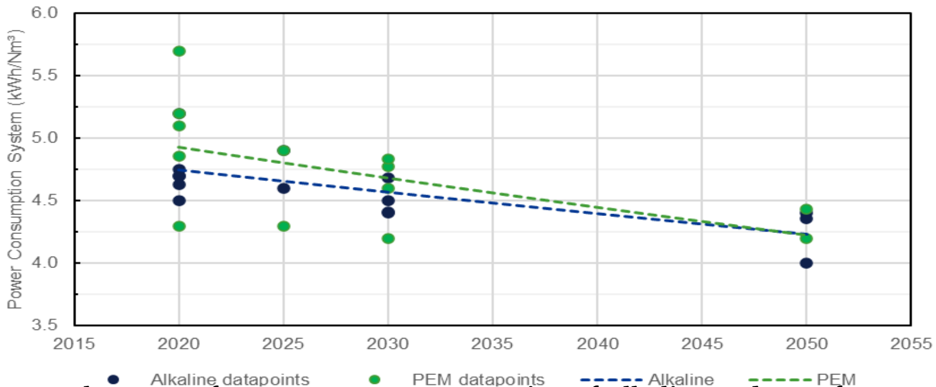


Figure 8-8 - Development of system power consumption of Alkaline and PEM for 1 MW reference.

The stack lifetime is provided in operating hours which represents operation at full load. There is still much unknown about degradation with partial load or intermittent operation. Degradation leads to a decrease in efficiency and as a rule of thumb, a stack reaches its lifetime after the efficiency has decreased by 10%. The figure below (Figure 29) is based on this 10% decrease in efficiency. This is of course an economic consideration as less or more efficiency loss can be accepted for a viable business case. A simple approach is to calculate the number of full load hours (e.g. 2 hours at 50% load count as 1 full load hour) and use the values in the figure to determine the time of stack replacement.

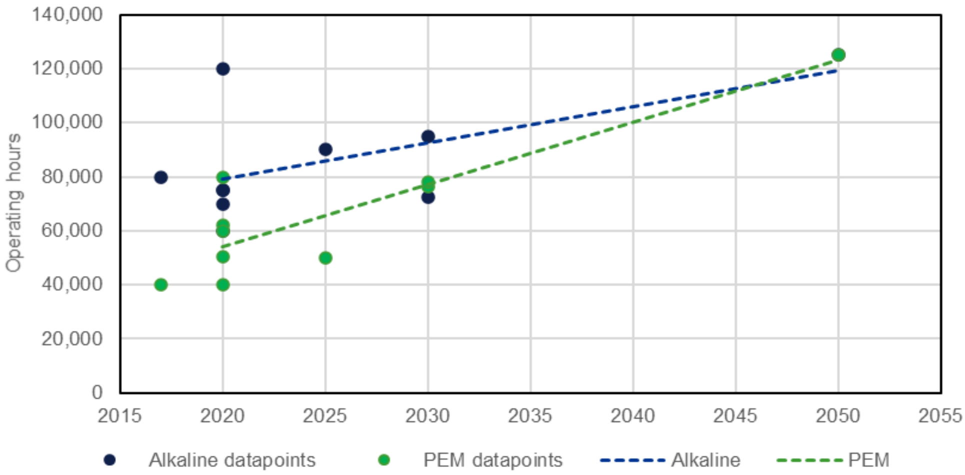


Figure 8-9 - Development of stack lifetime of Alkaline and PEM for 1 MW reference.

B.2.4 Scalability

Significant cost reduction can be achieved for electrolysers through economies of scale. The costs of certain components do not scale linearly with an increase in capacity and provide a cost advantage. This applies especially to vessels/tanks and pipes which make up a large part of the balance of plant[12] (BoP) of an electrolyser plant. A rule of thumb to estimate the economies of scale is called the 0.6 rule. With each increase in size, the cost will increase with an exponent of 0.6. In an electrolyser plant, however, a large part of the costs are for the stacks which do not have such scaling advantages. After reaching the stack capacity (a few MW depending on the manufacturer) scaling up simply means applying more stacks. Therefore, the stacks do not have much economies of scale after a few MW, while the BoP does have economies of scale.

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

$$\begin{aligned}\boldsymbol{Scaling\ advantage\ stacks}\ (\%) \\ = (\boldsymbol{Electrolyser\ capacity}\ (\boldsymbol{MW})^{\mathbf{0.95}})/\boldsymbol{Electrolyser\ capacity}\ (\boldsymbol{MW}) * \mathbf{100}\%\end{aligned} \quad (1)$$

$$\begin{aligned}\boldsymbol{Scaling\ advantage\ BoP}\ (\%) \\ = (\boldsymbol{Electrolyser\ capacity}\ (\boldsymbol{MW})^{0.75})/\boldsymbol{Electrolyser\ capacity}\ (\boldsymbol{MW}) * \mathbf{100}\%\end{aligned} \quad (2)$$

The effect of economies of scale is also provided in Figure 8-10 below.

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

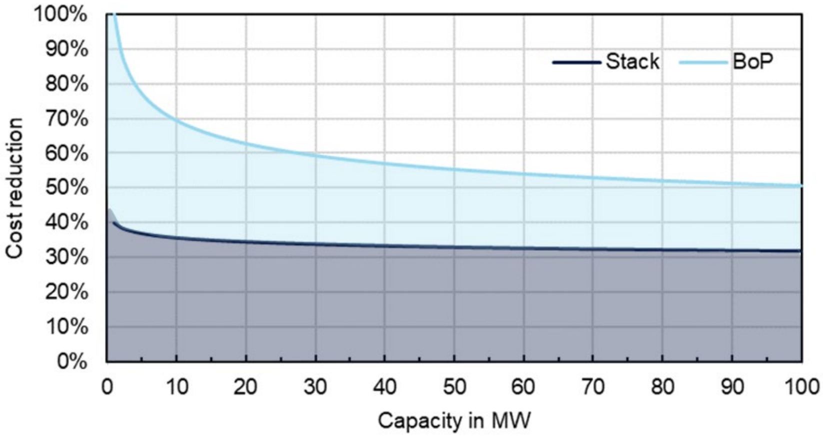


Figure 8-10 - Economies of scale for an electrolyser.

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

A conceptual design of a large-scale electrolyser plant (GW-scale) was done by ISPT and provides a reference for a possible design concept[13]. The design assumes a modular approach where modules are repeated to increase total capacity. Economies of scale apply to a single module and will decrease after modules are repeated.

B.2.5 Weight and space claim

The optimization of weight and space in electrolysers primarily stems from advancements in making Balance of Plant (BoP) systems more compact and the adoption of higher current densities, enabling smaller stacks to generate the same amount of hydrogen. These optimizations have not been the primary focus for most onshore hydrogen projects thus far, with other considerations taking precedence. However, some companies have started integrating electrolysers, mostly Proton Exchange Membrane (PEM) electrolysers, offshore. As a result, there is a considerable variation in the weight and space requirements among hydrogen production plants in general, indicating the ongoing exploration and experimentation in this domain. The weights and space claims that were assumed in the case studies in this report can be found in Appendix A.

B.2.6 Direct seawater electrolysis

Conventional alkaline and PEM electrolysers require water with very high purity, which is typically specified as a very low conductivity value (< 1 μS/cm) and referred to as demineralised or deionised water. The reason for this is to avoid the build-up and precipitation of salts, and avoid unwanted side reactions and degradation of the electrode and membrane materials. Techniques to remove ions include reverse osmosis, ion exchange and evaporation. An alternative is to electrolyse sea water directly, without or with minimal pre-treatment. This would eliminate the capital and operating costs of seawater desalination for green hydrogen production. Seawater contains mostly sodium chloride (NaCl) and much smaller quantities of other salts (Mg, Ca, K, sulphates). The salinity of seawater is on average 35 g/L.

[13] ISPT, "Gigawatt Green Hydrogen Plant," 2020.

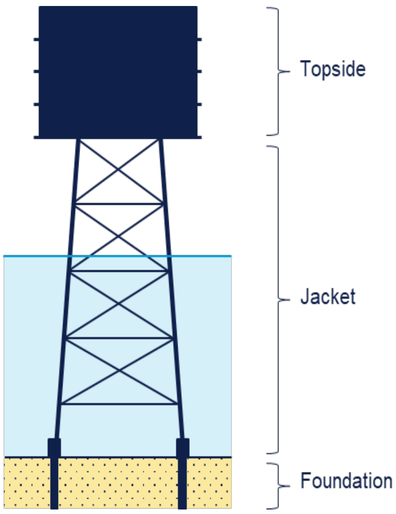
The current state of the technology & development expectation

The biggest challenge with direct seawater electrolysis is the formation of chlorine gas instead of oxygen at the anode of the electrolysis cell (electrolysis of a concentrated NaCl solution is the industrial process used to produce chlorine and sodium hydroxide, known as the chlor-alkali process).

Chlorine is very toxic and also corrodes many materials, particularly metallic substrates and catalysts in electrodes. The onset voltage of chlorine and oxygen are very similar, making it very difficult to inhibit the formation of chlorine. Current research is looking into catalysts that are selective to oxygen formation. The expectations for the future development of seawater electrolysis are low. The CAPEX and OPEX of seawater desalination are very small compared to the cost of renewables and electrolysers and therefore typically not worth the downsides presented. The energy consumption of reverse osmosis is <0.1% of the energy consumption of electrolysers.

- Current TRL: 2-3
- Commercial readiness expectation (Year): 2040-2050
- Limitations in offshore hydrogen production: The technology is still at the proof-of-concept stage and will not be applicable for offshore hydrogen production in the short to medium term. Based on preliminary assessment the advantages it offers to on-site desalination in terms of cost savings, operational efficiency and space savings are limited.

B.3 Hydrogen platform sub-structure



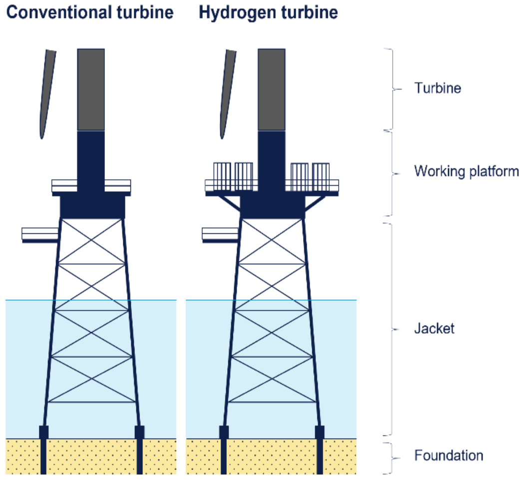
Offshore platforms have been deployed in the Oil and Gas industry for many years and are well-developed. Although the application for offshore hydrogen production is new and likely requires adaptations to "conventional" design (e.g. different safety measures, standardization of design, etc.) a rough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

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

The costs for a platform are divided into costs for the topside structure, costs for the substructure/jacket and the costs for the foundation. A visualization of the three elements is provided in Figure 8-11 on the right.

B.4 Hydrogen turbine sub-structure

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



Hydrogen-generating turbines are still conceptual and detailed designs are not yet in place. This section, therefore, assumes DNV's view on how a hydrogen-generating turbine could be designed. This design assumes the jacket working platform to be extended to allow for placing electrolysis equipment. The equipment includes the power transformers, converters, stacks, gas treatment, water treatment, cooling and other equipment which is placed on the platform in (40 ft.) shipping containers. The figure to the right provides a visualization.