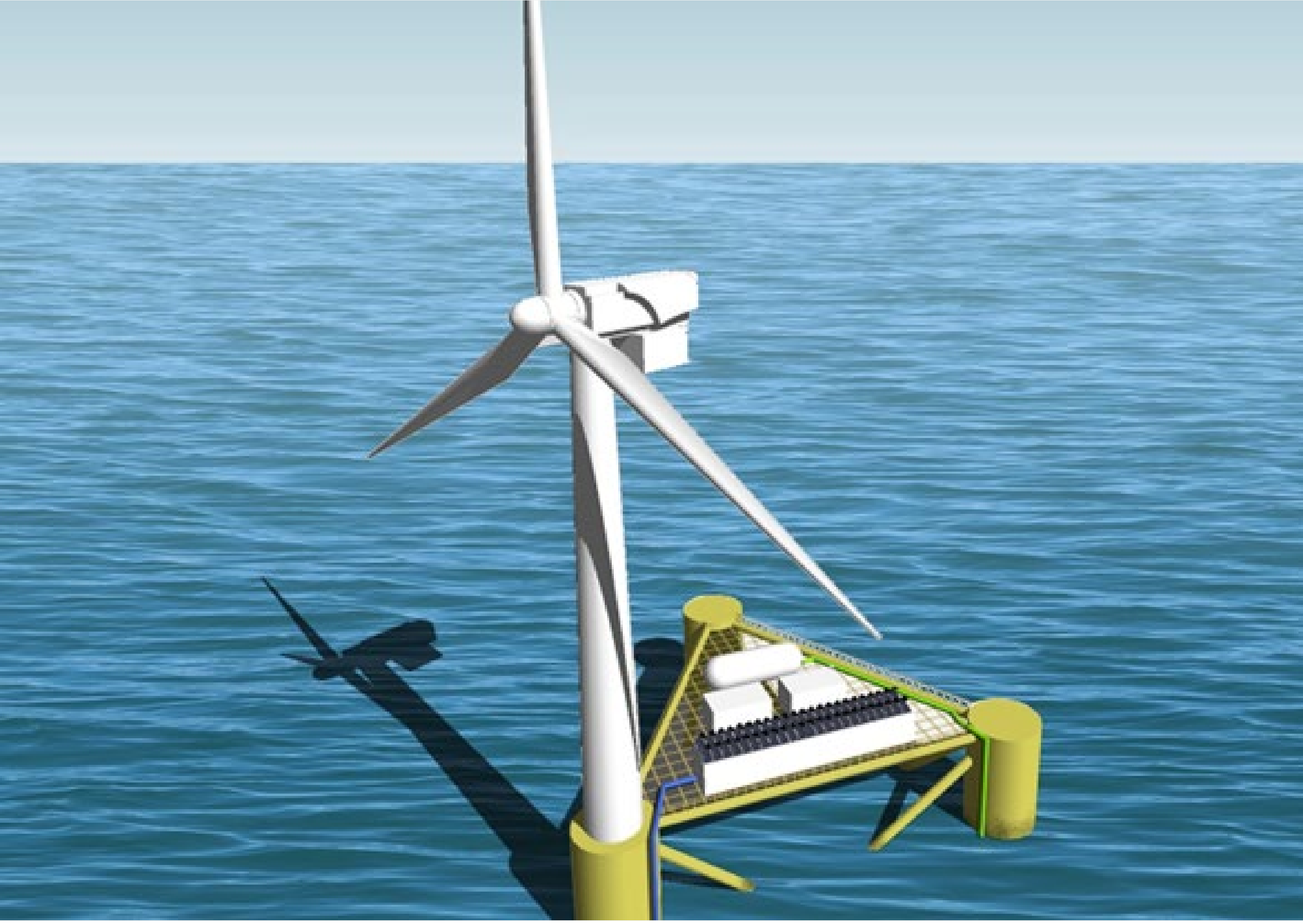

Dolphyn Hydrogen

Phase 1 - Final Report

Comprising:
Phase 1a – Concept Select
Phase 1b – FEED for 2MW Scale Prototype

Public Report

9 October 2019

Project No.: 0500255

The business of sustainability

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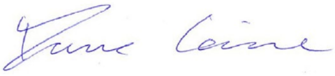
9 October 2019

Dolphyn Hydrogen

Phase 1 - Final Report

Public Report



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ABOUT ERM

ERM is a global sustainability, environmental, health, safety and risk management consultancy that is increasingly helping clients to operate in a low carbon world. We have helped several blue chip companies develop sustainability strategies that define material issues, stakeholder engagement, goal setting and KPIs.

Our work on low carbon energy transition and hydrogen covers many of the UK's leading projects (e.g. H21, Hy4Heat, HyNet, H100, HyGen, Acorn). We have extensive experience on leading renewable projects, including major wind farm projects both offshore and onshore. We are the originators, developers and project manager for the Dolphyn project, developing an innovative technical and economic solution for producing green hydrogen at scale from offshore wind.

ERM often provides advice that gives clients the confidence to diversify their business and is typically the culmination of several phases of work as outlined below.

Respond to Climate-Related Financial Impacts
ERM were the lead authors on behalf of the TCFD for the technical guidance for assessing climate-related financial risks and opportunities. Recognising our TCFD expertise leading industrial companies, who are typically heavy emitters of CO2, have appointed ERM to work with them to assess the financial drivers on their business from the energy transition and to define strategic responses to mitigate risks and capture new growth opportunities. Through the 40+ years work we have undertaken in the financial and corporate sectors, we understand both investors' key concerns and companies' potential challenges to overcome in implementing TCFD.

We help our clients deliver Low-Carbon Business Growth
We help clients to shape their strategic response to the Energy Transition; this usually follows a detailed options appraisal that has assessed the techno- economic feasibility of different strategies and/or technologies. ERM's expertise extends way beyond board rooms, we are fully equipped to support companies at a site-level delivering new innovative low-carbon projects, from advancing hydrogen and CCUS projects to supporting companies in reducing their overall product carbon intensity across their portfolio. ERM has current insights into CCS / CCUS policy from our work with the CO2 Capture Project (CCP) and will be presenting our latest report at COP25 in November. This presents a survey of CO2 storage regulations from a range of countries including the USA, Canada, UK, and Australia.

Ensure Financial Resilience
Beyond implementation, a key part of our work is to measure and demonstrate a clients' stated actions i.e. to demonstrate the positive impact of these low carbon advancements, and ultimately helping to ensure companies' reputations as responsible corporate citizens and retain their License to Operate. We support companies in their reporting (e.g. TCFD, CDP, corporate and sustainability reports), and engagements with investors, government and society more widely.

ERM works with the world's leading organizations, delivering innovative solutions and helping them to understand and manage their sustainability challenges. ERM is a founder member of the WBCSD and has contributed to their publications including several sector SDG Roadmaps. We have more than 5,500 people in over 40 countries and territories working out of more than 160 offices with London being our Global HQ. www.erm.com

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Acronyms and Abbreviations

Acronym	Definition
AHT	Anchor Handling Tugs
ALARP	As Low As Reasonably Practicable
BEIS	Department for Business, Energy & Industrial Strategy
BNEF	Bloomberg New Energy Finance
CAPEX	Capital Expenditure
CCC	Committee on Climate Change
CCS	Carbon Capture and Storage
CDP	Climate Disclosure Project
CRS	Comment Resolution Sheet
COMAH	Control of Major Accident Hazards
CTV	Crew Transfer Vehicles
DSV	Diving Support Vessel
ERM	Environmental Resources Management Ltd.
EYA	Energy Yield Assessment
FEED	Front End Engineering Design
FLNG	Floating Liquefied Natural Gas
FPSO	Floating Production Storage and Offloading
HAZID	Hazard Identification
HAZOP	Hazard and Operability Study
HGE	Hydrogen Gas Embrittlement
HVAC	Heating Ventilation and Air Conditioning
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IRENA	International Renewable Energy Agency
MHI	Mitsubishi Heavy Industries
NOV	National Oilwell Varco
ODE	Offshore Design Engineering
OEM	Original Equipment Manufacturers
OPEX	Operating Expenditure
ORE	Offshore Renewable Energy
P&ID	Piping and Instrumentation Diagram
PE	Polyethylene
PEM	Proton Exchange Membrane
PFD	Process Flow Diagram
PLEM	Pipeline End Manifold
PPI	Principle Power
PVC	Polyvinylchloride
RAM	Reliability and Maintainability
ROV	Remotely Operated Vehicle
SAMS	Safety Action Monitoring Sheet
SBRI	Small Business Research Initiative
SDG	Sustainable Development Goals
SGN	Scotia/Southern Gas Network
SMR	Steam Methane Reformation
SOE	Solid Oxide Electrolyser
SOLAS	Safety of Life at Sea
TCFD	Task Force on Climate-related Financial Disclosure
WRA	Wind Resource Assessment
WTG	Wind Turbine Generator
WBCSD	World Business Council for Sustainable Development

EXECUTIVE SUMMARY

ERM has developed a concept design, Dolphyn (**D**eepwater **O**ffshore **L**ocal **P**roduction of **HY**droge**N**) for the production of 'green' hydrogen at scale from offshore floating wind. The concept integrates a wind turbine, desalination unit and electrolysis onto a single floating sub-structure to produce hydrogen that can be transported to shore via pipeline. The design is being developed to Front End Engineering Design (FEED) stage under Phase 1 of the Hydrogen Supply Competition, funded by the BEIS Energy Innovation Programme (2016-2021).

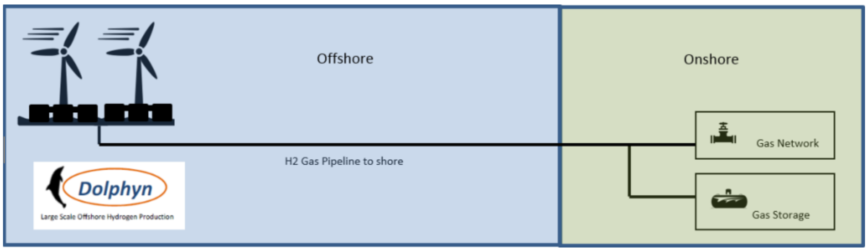
The Phase 1 work is split into two parts:

- Phase 1a – Concept Select
- Phase 1b – FEED and Forward Development Plan.

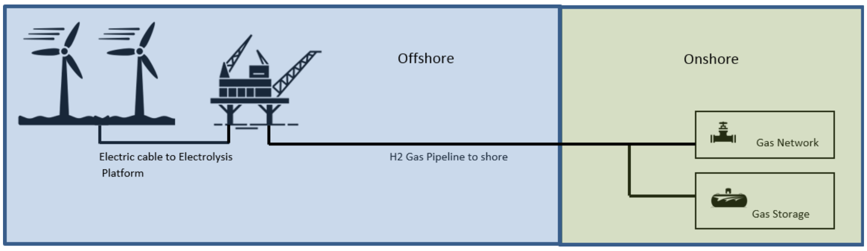
Phase 1a – Concept Select

Phase 1a 'concept select' stage of the project includes an evaluation of the technical and economic feasibility of selected design concepts for producing bulk scale hydrogen from offshore floating wind. It also presents a review of the current status of relevant technology as well as predicted future technology and manufacturing enhancements and cost improvements. Gaps in technology needed to commercialise or enhance the design options have been assessed and incorporated. The 3 design options considered are:

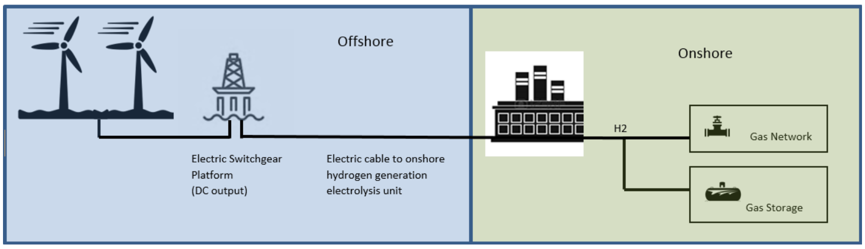
- **Case 1**. Dolphyn offshore floating wind farm with hydrogen export pipeline to shore, with two sub-structure design options
    - Semi-submersible design option
    - Spar design option



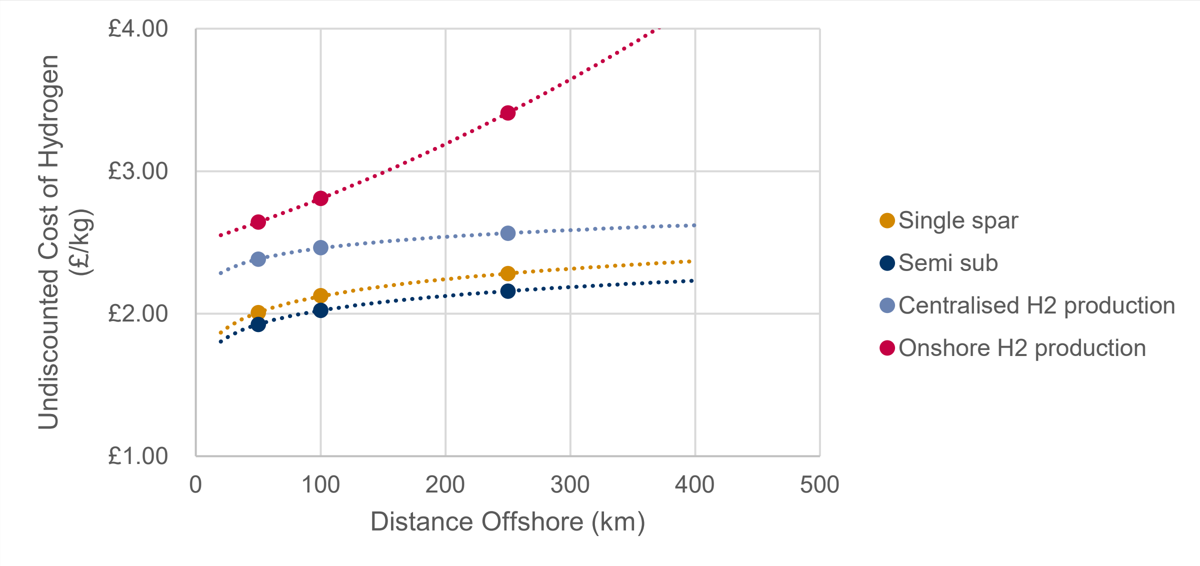
- **Case 2**. Offshore floating wind farm with a centralised electrolyser vessel and export pipeline to shore



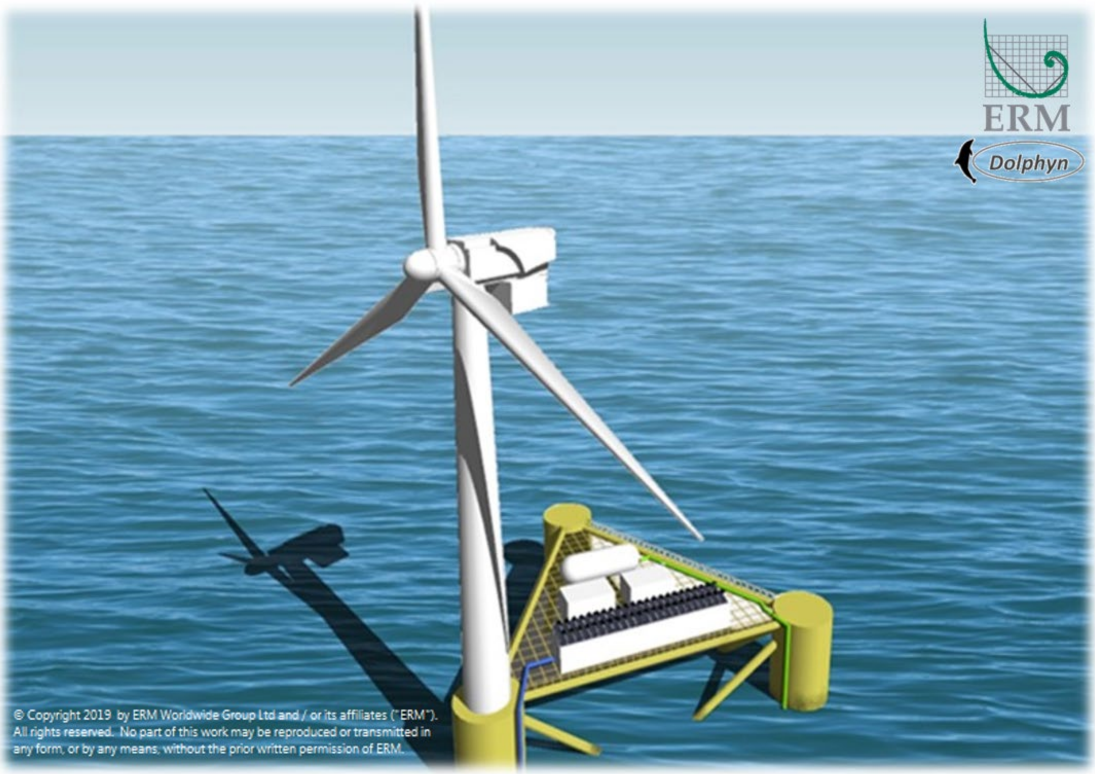
- **Case 3**. Offshore floating wind farm with an HVAC or HVDC cable to electrolysers located onshore



The results from the evaluations (see figure below) indicate that the Dolphyn (Case 1) semi-submersible design concept is the most economically advantageous solution for the bulk production of green hydrogen. The next most advantageous is the option with centralised hydrogen production (Case 2) with Case 3 being the most expensive option. Case 3 is also the option in which costs increase most significantly with distance offshore.



The predicted cost of hydrogen for the Dolphyn semi-sub option when produced at scale (20 x 20 array of 10MW turbines) is competitive (below £2/kg up to 100km). It is also the most technically feasible option, with the required topside equipment being relatively easy to install in the shipyard prior to being towed to location. It is considered that this option provides a credible and sustainable solution for large scale production of green hydrogen for the UK. An illustration of the selected concept is shown below:

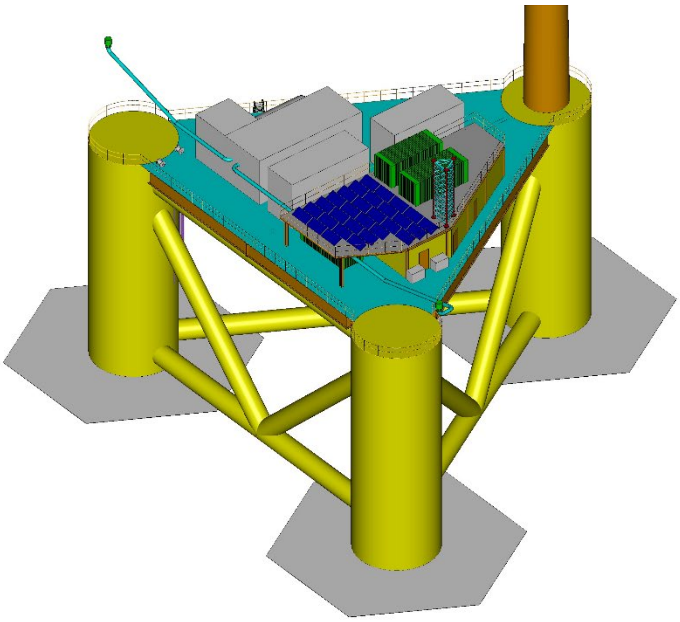


Phase 1b – FEED and Forward Development Plan

Phase 1b 'FEED and Forward Development Plan' of the project includes a summary of the design activities undertaken to bring the concept design to a point where it is technically and economically viable. The following key activities are described:

- Front end engineering design (FEED) for a 2 MW prototype
- Detailed financial modelling including sensitivity of alternate commercial scale projects e.g. 12 or 15 MW turbines
- Project Development Plan

The FEED work has determined that the design is technically and economically feasible. The engineering, financial, and development planning have been developed sufficiently to enable the next phase of engineering to be undertaken with a high degree of confidence of reaching a final investment decision for building a 2MW prototype facility by Spring 2021. A 3D visualisation of the prototype design developed is shown below:



The cost estimates established during concept select have been refined, with the headline results for the 2MW and 10MW scales remaining as similar values but with an increased confidence in their validity.

The base case assumed a 10MW wind turbine size, however the financial model also investigated the difference in lifetime costs for 12MW and 15MW.

- If the WTG size was adjusted to **12MW** then the associated wind farm Capex (per MW output) reduced 8%, and the associated annual Opex (per MW output including interest repayment but excluding electrolyser stack replacement) also reduced 8%. The implied hydrogen cost therefore reduced from £1.93/kg to **£1.79/kg** (undiscounted).
- If the WTG size was adjusted to **15MW** then the associated Capex reduced 15%, and the associated annual Opex (per MW output including interest repayment but excluding electrolyser stack replacement) reduced 17%. The implied hydrogen cost therefore reduced to **£1.65/kg** (undiscounted).

From this analysis, it can be seen that using an increased wind turbine size would be beneficial to the project from an economics perspective. ERM has assumed a 10MW turbine for its analysis in order to be conservative.

The focus of the FEED is to develop the prototype model, also referred to as the 2 MW demonstrator, as part of a commercial development plan. The key stages to commercialisation are as follows:

Dolphyn Hydrogen Project: Size of Development	Date	Hydrogen Production Rate (Tonnes/yr)	Hydrogen Production Rate (TWh/y)
2MW - prototype (single operating unit)	2023	180	0.006
10MW – pre-commercial facility (single operating unit)	2026	900	0.03
100 MW- first commercial offshore hydrogen wind farm (10 x 10MW turbines)	2032	9,000	0.30
4GW – first full scale 20 x 20 array hydrogen wind farm (400 x 10MW turbines)	2037	360,000	12.0

Having developed the 2MW prototype FEED, the work will now progress to Phase 2a of the project to perform detailed engineering, obtain consent for the site and to ensure regulatory compliance requirements are met. This work will start around the end of 2019 and enable a final investment decision on the prototype to be made by the middle of 2021. Phase 2b (procurement, construction and commissioning) will then follow with the aim of having a prototype built and operating by the summer of 2023.

1. INTRODUCTION

ERM has developed a concept design (Dolphyn - **D**eepwater **O**ffshore **L**ocal **P**roduction of **HY**droge**N**) for the production of large scale 'green' hydrogen from offshore floating wind. This concept design is being compared to alternative offshore options and further explored and developed to Front End Engineering Design (FEED) stage under the Hydrogen supply competition, funded by the BEIS Energy Innovation Programme (2016-2021).

1.1 Hydrogen Supply Programme

The aim of the Hydrogen Supply Programme is to identify and test approaches to supplying bulk low carbon hydrogen; either to the gas grid, industry, power, transport, or import terminals. Low carbon hydrogen could play an important role in decarbonising the industry, power, heat and transport sectors. However, for a market to grow, potential users (in any application) need to be confident in supply of sufficient amounts of low carbon hydrogen at a competitive price. By supporting innovative pilots to help develop the process and technologies required to supply bulk low carbon hydrogen, this Programme seeks to address the cost differential between natural gas and low carbon hydrogen.

The Programme seeks to identify and demonstrate bulk low carbon hydrogen supply solutions, which have the potential to be replicated at significant scale in identical or similar applications, that can meet the challenges of supplying the gas grid, industry, power, transport and upgrading our import terminals to be able to handle hydrogen (or hydrogen carrier). The Programme is technology-neutral, however, it takes a portfolio approach to funding a range of solutions.

The proposed bulk low carbon hydrogen solutions include: low carbon production (through fossil fuel reformation with CCS), zero carbon production (using zero carbon energy such as electrolysis, nuclear, or biomass with CCS), the import infrastructure for hydrogen, the storage of hydrogen, or the bulk provision of hydrogen closer to the end user. These solutions could include the use of hydrogen carrier.

A two-stage Small Business Research Initiative (SBRI) pre-commercial procurement process is being used to evaluate large scale hydrogen production options:

Phase 1, Feasibility studies. Project teams will carry out feasibility studies that will identify:

- An assessment of the market size and export opportunities for the technology for bulk low carbon hydrogen supply.
- A detailed engineering design for each hydrogen supply solution, against which an assessment could be made on a number of metrics. These are likely to include: capital and operating costs, process risks (reliability), the availability and the impact of variable demand, the hydrogen quality, the potential to mitigate greenhouse gases, the build rate, and how the process could be scaled. Process modelling or small-scale trials may also be required to verify the design, the use of modelling or demonstration to support the hydrogen supply solution will be assessed under criterion 4: project financing.
- A detailed development plan for each solution describing the key development steps to commercialisation, including the key barriers and risks. This should include a detailed focus on the component(s) to be piloted in Phase 2. Each step will be costed.
- A detailed assessment of the business plan on how the process will continue to be developed after the funding for the pilot ends.

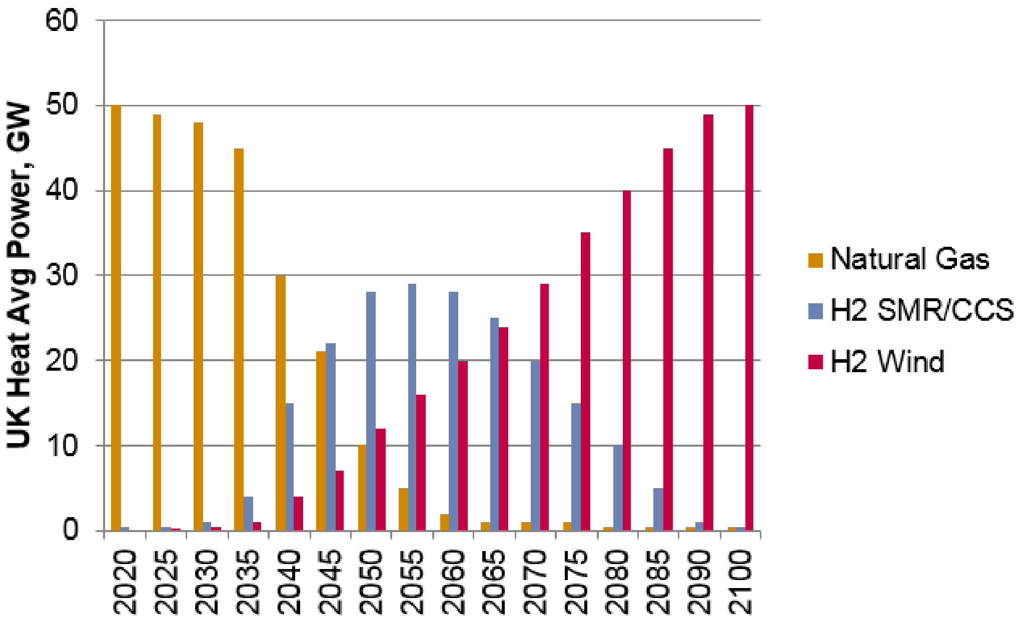
Phase 2 is for projects that have been down-selected from Phase 1, based on the information contained in their Feasibility Study. This phase will result in the implementation and demonstration of a hydrogen supply solution and will consider applications to pilot key components or further develop the design of the new hydrogen supply solutions. A pilot demonstration is not limited to a physical demonstration and may only be for part(s) of the process. This could include detailed process modelling or engineering design. The Phase 2 demonstration projects will be selected based on the feasibility studies submitted for Phase 1 – no completely new applicants will be able to enter the Competition at Phase 2, although some variation in project partners may be permitted.

1.2 Dolphyn Concept

The Dolphyn concept employs a modular design, integrating electrolysis and a wind turbine (nominally 10MW) on a moored floating sub-structure to produce hydrogen from seawater using wind power as the energy source. The component parts of the concept, whilst emerging technology, are all at a high 'technology readiness level' providing a good degree of confidence that the solution will work at scale.

Offshore Renewable Energy Catapult [1] indicate a rapidly expanding market for hydrogen for decarbonised heat and transport applications in the UK and Europe, particularly from 2030 onwards (Figure 1.1). Assuming a 100% hydrogen gas network, it is forecast that initially the market needs will most likely be met by 'blue' hydrogen, generated using natural gas and steam-methane reformation with carbon capture and storage (CCS). However, a steady transition to 'green' hydrogen is anticipated thereafter and wind offers an outstanding opportunity, particularly for countries such as the UK, Ireland, Norway, Netherlands and Denmark. Around 80% of Europe's wind resource is located in deep water (>60m) and a floating wind solution, developed in the UK, can unlock this huge potential.

Figure 1.1 Hydrogen supply for 100% gas network conversion



ORE Catapult [1]

It is notable that offshore wind and electrolyser costs have decreased significantly over the last decade, whilst electrolyser efficiency has increased, and we see this trend continuing. We expect prices for floating offshore wind to decrease rapidly, as they have for onshore and 'bottom-fixed' offshore wind, and potentially at an even greater speed. The performance of initial floating wind turbines, as now installed offshore Scotland (Hywind), has exceeded expectations and recent electrolyser developments have proven that the key component parts of the technology are now in place.

2. TECHNOLOGY READINESS

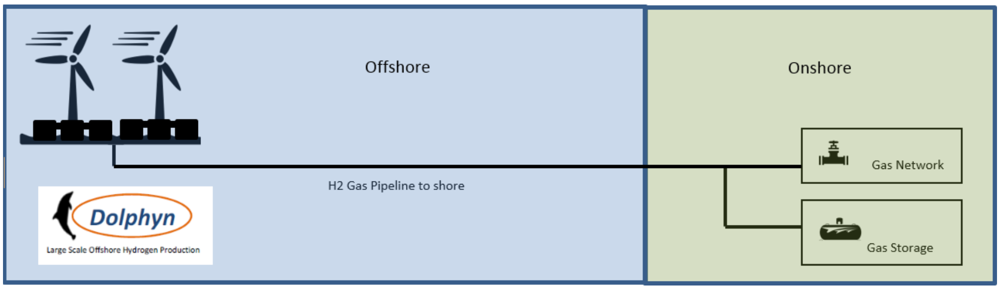
2.1 Identification of Concept Options

There are two sub-structure options to be considered within this project for the Dolphyn concept: The first involves a 'semi-sub' design (base case) in which a desalination unit and PEM electrolyser are located on a tri-angular semi-sub structure at opposing corners from the turbine tower. The second option is a 'spar' design in which the desalination unit with seawater lift is positioned inside the turbine tower, providing desalinated water to electrolysers mounted externally on a small deck above the splash zone. Both of these options were selected by ERM prior to the current project based on sub-structure designs (Windfloat Atlantic and Hywind) that have already been proven at large scale (>6MW) in real world offshore conditions (i.e. harsh offshore environments).

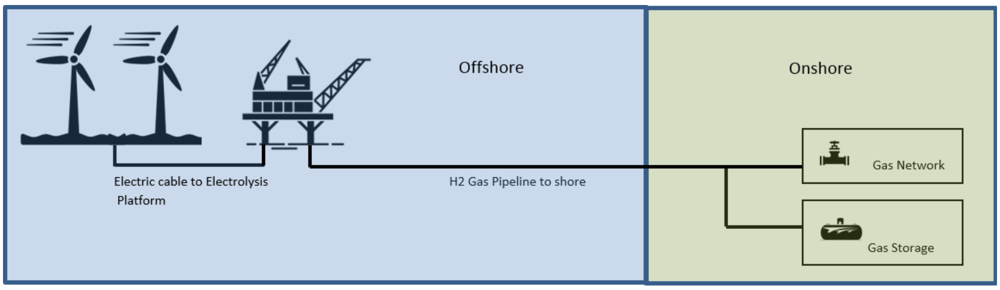
Each 10MW (base case capacity) Dolphyn facility would generate 'green' hydrogen (>800 Te/yr) which would be exported at pressure (30-50 bar) via a single flexible riser. This would connect to a sub-sea manifold with flow lines from other individual turbines in the field and the gas being exported back to shore via a single trunk-line. The 400 turbine field (20 x 20 array) would have a capacity of 4GW, producing sufficient hydrogen to heat more than 1.5 million UK homes. The pipeline back to shore will act as a significant storage facility.

The Dolphyn design (semi-sub and spa options) is to be evaluated both technically and economically against two other offshore wind layout configurations to determine which offers the most attractive overall solution for producing hydrogen at scale. A total of 3 options (Cases 1-3) are therefore to be considered as follows:

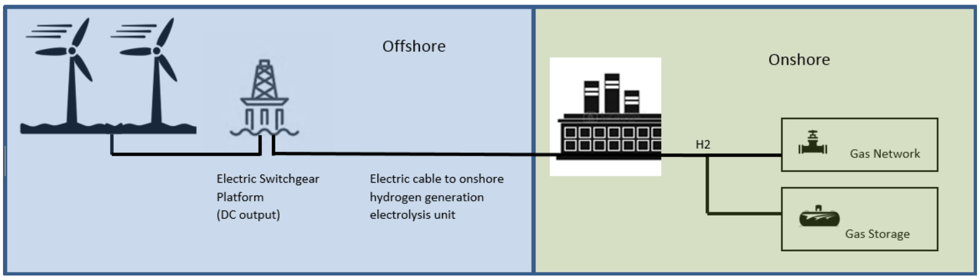
- **Case 1**. Dolphyn offshore floating wind farm with hydrogen export pipeline to shore, with two sub-structure design options
    - Semi-submersible design option
    - Spar design option



- **Case 2**. Offshore floating wind farm with a centralised electrolyser vessel and export pipeline to shore



- **Case 3**. Offshore floating wind farm with an HVAC or HVDC cable to electrolysers located onshore (an additional review of a fixed bottom equivalent wind farm has been included for comparative purposes under this option)



To enable a valid comparison to be made of each option, the following assumptions were adopted for each case:

- Includes all systems required to deliver H2 onshore (i.e. export, compression, cabling, conversion, and offshore/onshore electrolysis)
- 3 offshore distances (shore to wind farm) for comparison:
  - 50km
  - 100km
  - 250km

The concept select of the leading design options required a scope that enabled a like for like comparison of the realistic readiness of technology. The scope includes the full lifecycle costs of all design options based on the expected status of technology over an illustrative construction and operation project timeline. The concepts considered also include all technology requirements to deliver hydrogen onshore (i.e. full cost of export pipelines are included).

2.2 Technology Review

The assessment of current and emerging technology was conducted in a systematic way building on the work carried out by ERM in the early project development. The aim was to identify a range of existing proven technologies, and to implement and operate them using existing offshore design industry techniques.

The identification of system applicability for use on the Dolphyn project was conducted using a mix of literary reviews and original research through interviews with equipment vendors, engineers and academia. The content of these discussions included physical parameters (e.g. size and weight), interactions with other systems, current usage types and scale, as well as efficiency characteristics, likely upcoming improvements in cost and technology performance, maintenance and operational requirements, and identification of any key risks or concerns related to using the technology offshore. We would like to thank the following companies and organisations for their input into our review:

2H Offshore	Burckhardt Compressors
BP	Cadent
Doris	Engie
Hatenboer Water	Health and Safety Executive
ITM Power	MAN
MHI Vestas	NEL
NOV	ODE
ORE Catapult	Overdrick
Principle Power	Scottish Enterprise
SGN	Siemens
Technip	Tractebel
Vryhof	

Technology information sheets were compiled detailing the key findings from vendor reviews.

Many of the technology items reviewed are considered emerging technology but sufficient experience of their usage in similar applications is available to demonstrate their technical readiness either directly or with relatively minor modification. This section summarises the readiness of each aspect of the concept and highlights the inherent benefits, implied challenges, and potential enabling works. Where enabling works are known to be in progress on other projects this is highlighted as a mutually beneficial technology.

The equipment and systems considered have been classified using the following summary of the level of modifications expected to be required by the Dolphyn project:

Ready and fully proven for application	⊖
Negligible modifications/minor adjustments required	⊖
Small modifications (<£1M) required	⊖
Significant modifications (>£1M) required	⊖
Requires further major development (not considered suitable currently)	⊖

2.2.1 Design Concept

The design concepts under consideration are based on combining existing proven technology and applying it for use in a novel way. Each concept is based on a 20 x 20 array of 10MW floating wind turbines. The wind farm will be located far from shore, and a range of distances have been considered to provide an understanding of the impact of distance to the concept being selected. The design concepts under review are all based on the requirements for delivery of hydrogen onshore.

All of the design concepts under consideration can achieve the same objective - to develop hydrogen at a large scale without carbon emissions at the point of generation or end use. A stand-by power module is included within the design to provide stand-by power for equipment when the wind is not blowing within operational limits.

2.2.2 Primary Systems

The design concepts under consideration have been divided into their primary systems and each system reviewed in turn. The review for each system comprised of a literary review and interviews with vendors and engineering contractors. In many cases similar systems are applicable for use in multiple design configurations (Cases 1-3) as shown in Table 2.1.

Table 2.1 Summary of primary systems

System	Dolphyn (Semi-sub)	Dolphyn (Spar)	Centralised Electrolysis	Electrolysis Onshore	Fixed Bottom
1. Wind Turbine Generator (WTG)	X	X	X	X	X
2. Sub-structure	X	X	X	X	X
3. Mooring and Anchors	X	X	X	X	
4. Electrolysis	X	X	X	X	X
5. AC-DC Rectification	X	X	X	X	X
6. Desalination	X	X	X	X	X
7. Seawater Lift	X	X	X	X	X
8. Risers and Gathering	X	X			X
9. Export Compression and Pipeline	X	X	X		X
10. Inter-array Cabling			X	X	
11. Export Transmission				X	
12. Central Offshore Vessel for Electrolysis			X		
13. Onshore Electrolysis Buildings				X	
14. Stand-by Power	X	X	X	X	X

2.2.3 Wind Turbine Generator

Significant improvements have been made in offshore wind turbine generator (WTG) technology resulting in increases in performance in most features (including generation capacity as well as improved uptime). The technology for offshore WTGs is maturing, resulting in decreased CAPEX and OPEX, as well as a high confidence in the technology's performance.

The main addition to WTGs for use in a floating environment is the requirement for a stability management system to ensure movement in the sub-structure (e.g. due to wave loading) is not passed onto the WTG tower. Excessive movement in the tower results in decreased performance and increased mechanical fatigue of rotating and flexible parts leading to an increase in maintenance costs and WTG downtime. In extreme cases excessive movement in the tower can lead to failure of the components. A number of demonstrator projects have been completed with WTGs at around the 2MW scale proving the technology. The next generation of floating wind turbines are already being developed at around the 10MW scale (e.g. Kincardine project) and beyond.

The operating range for WTGs has increased over time with an operating wind speed range of 3m/s to >25m/s, and a temperature range from -10 to +25deg C. All potential locations for the Dolphyn project in the North Sea fall within these parameters for the majority of the time.

A supply of power is required to the WTG at all times to maintain essential systems (e.g. yaw control). Whilst these power requirements are relatively modest a suitably sized backup/standby power supply must be available during periods where energy cannot be produced by the WTG directly (e.g. low/high wind conditions).

WTGs for offshore use have recently been proven and demonstrated. The high quality of deep water wind resources particularly around the UK are highly desirable with capacity factors of over 60% anticipated [8]. Offshore floating wind turbines are expected to be developed at increasing scales over the next decade with a mature industry in place by the early 2030s. The development of the sector at this scale provides improvements in WTG development and operating costs. If large scale orders were to materialise in the future due to projects such as Dolphyn, then further cost improvements would be expected.

All options considered in this assessment require WTGs suitable for use in a floating environment, with none of the design concepts expected to impact the WTG design or performance. The WTG is similar for all design concepts being considered, and as such is not a primary driver in concept selection. No modifications are expected to be required for usage in the Dolphyn project.

The WTG is a high value item and as such is an important factor in understanding the financial viability of the project. Selection of an appropriately designed and proven WTG for offshore use is essential in delivering the project and is a key early activity in FEED.

2.2.4 Floating Sub-Structure

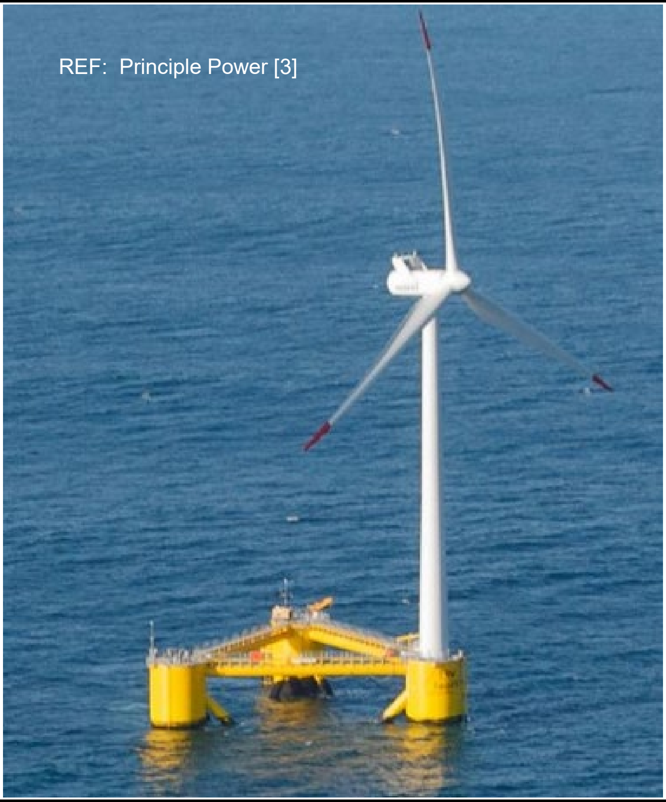
Floating sub-structures have been tested and proven in the offshore oil and gas industry in a wide variety of operating environments. Their use in oil and gas operations range in size from floating production storage and offloading facilities (FPSOs), through semi-submersible drilling vessels, floating production towers, and mooring turrets. This range of design concepts extends to the offshore floating wind industry with a wide variety of designs at various stages of development. The Carbon Trust [2] summary of the main foundation typologies from 2015 remains a valuable resource, although technologies have advanced.

Two sub-structure designs have been tested and proven to work in offshore floating wind projects at a multi-MW scale. The first is Principle Power's semi-submersible type design, the second is Equinor's Spar type design. In both cases a field layout in a grid of 20 x 20 structures is anticipated with a separation of 1 km between each structure.

Semi-Submersible Sub-structure

The semi-submersible structure reviewed is the WindFloat type design from Principle Power, currently in use as part of the WindFloat Atlantic project [4].

Figure 2.1 WindFloat Semi-submersible Platform



The design comprises a triangular base of floating cans with the turbine located directly onto one of the corners. The design has been proven to work at 2MW scale in the Windfloat Atlantic and Kincardine projects in Spain and Scotland respectively. A project is currently underway to implement a larger 8.4 MW turbine as an extension to the WindFloat Atlantic project.

The triangular base creates a large footprint that would be well suited to create a deck area required to locate the hydrogen production facilities. Discussions with vendors of the required process equipment indicates that there would be sufficient deck area available without extending the footprint of the sub-structure, although the deck will require an increase in height to ensure it is located out of the splash zone. This increase in deck height and the additional weight of production facilities will influence the centre of gravity, requiring the ballasting system and sub-structure dimensions to be modified to ensure the turbine remains stable.

The semi-submersible sub-structure enables the turbine to be assembled in port (including installation of all hydrogen processing equipment) before being towed into location for hook-up and commissioning. The dimensions of the turbine and sub-structure require a large shipyard with sufficient water depth and crane height to enable construction. The semi-submersible sub-structure requires a minimum water depth of around 50 m.

Spa Sub-structure

The spar sub-structure reviewed is similar to the design developed by Equinor and used on the HyWind project, currently located off the east coast of Scotland.

Figure 2.2 HyWind Spar Sub-structure Design

The design comprises an extension on the main turbine tower vertically oriented downwards with ballasting in the sub-structure to provide stability. The design has been proven to work at a 2.3 MW scale in Norway, and at 6 MW scale in the UK North Sea (5 x 6MW units deployed on the Hywind project offshore Aberdeen).

The spar type design does not have a large horizontal footprint that would naturally lend itself to supporting a deck area. Converting the spar type design for use with the Dolphyn project therefore requires a supported semi-circular deck area to be extended out of the side of the vertical spar tower above the splash zone. The addition of a deck cantilevered from the main tower will impact the centre of gravity possibly requiring a redesign of the sub-structure or ballasting systems.

Due to the requirement to locate a deck connected to the central tower, the size of the deck area needs to be optimised as it will be a key driver to cost and motion sensitivity. The electrolysis package will therefore need to have the smallest footprint possible. Early discussions with electrolyser manufacturers indicate that the electrolyser package could be redesigned for a vertical orientation to minimise the horizontal footprint but this would require a complete redesign of the system and would be highly expensive.

The spar type design has a large water depth requirement due to the relatively long spar sub-structure. During installation the spar sub-structure is towed into place, before being vertically oriented and the blades installed in situ. The installation of turbines using this process requires a sufficient weather window to allow all activities to be completed, which may be a significant period of time in some distances from shore. It also requires a heavy lift vessel increasing the installation costs compared to the semi-sub design. The spar type sub-structure requires a minimum water depth of around 100 m.

2.2.5 Moorings and Anchors

Mooring and anchoring systems have been used in a wide variety of marine applications including the mooring of floating stationary production sub-structures in the oil and gas industry. Catenary mooring systems are used for both the semi-submersible and spar type sub-structures considered in this design. Catenary mooring systems comprise chains or wires spread moored a horizontal distance from the turbine sub-structure. The weight of the mooring chains hold position although the design must accommodate a reasonable degree of horizontal movement. Mooring lines can be produced to lengths to suit the water depth and anchor spread requirements. At very large depths the weight of the mooring lines may place an excessive load on the floating sub-structure affecting buoyancy. In these cases buoyancy aides can be added to the mooring lines to reduce loading. Mooring of floating sub-structures has been achieved in this way for water depths in excess of 1000m.

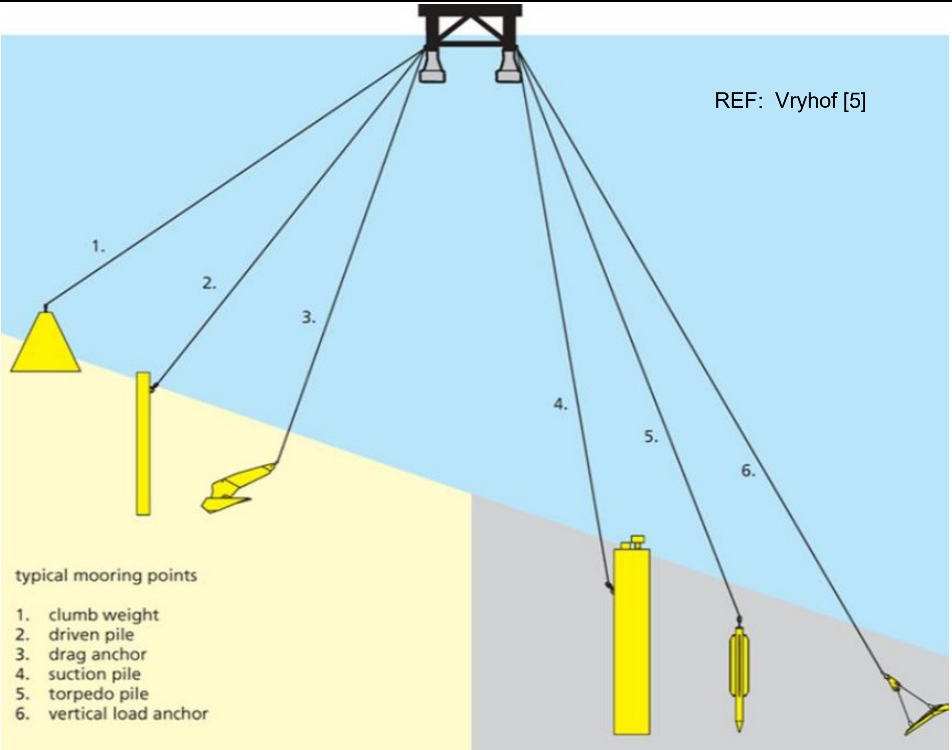
The number of mooring lines required is expected to be around 3 mooring lines for each of the semi-sub and spar type designs at a 2 MW scale. 10 MW scale systems have not been proven at commercial depths, discussions with vendors indicate that the spar type design may require additional mooring lines than the semi-submersible design at large scale. An estimate of 6-8 moorings lines was proposed although since this remains anecdotal all concepts are considered to have a similar mooring configuration for comparison purposes.

A variety of anchoring systems are available, the most common are shown in Figure 2.3. Catenary mooring systems are often used with drag anchors due to their ability to handle horizontal loading, relatively low cost, and ease of decommissioning. The selection of anchor type for the final development will primarily be driven by the site specific seabed conditions, with gravity anchors or driven pile anchors used for firmer seabed conditions. Drag anchors require softer sediment or sand, making seabed condition an important component of site selection for large scale commercial deployment.

Larger scales of wind turbines can be supported by drag anchors of a larger size and weight with no modifications required for use at the 10 MW scale. Drag anchors are currently manufactured in a manual process with opportunities for cost reduction through automation at larger scales of output.

Drag anchors are preferred for all floating design options under consideration and have been used as the basis for this comparison.

Figure 2.3 Anchoring options



The offshore turbine layout is expect to be in a 20 x 20 grid with a separation distance of around 1 km between turbines. This is ample to allow sub-structure movement for all mooring and anchoring types without risk of collision. No benefits have been taken for sharing anchoring points at this stage, however it is possible that installation efficiencies may be gained by installing common anchoring points for multiple mooring lines.

2.2.6 Electrolysis

Electrolysis technology has improved significantly in the past decade with commercial readiness being a key focus area. Electrolyser deployment has increased to a rate of around 100MW per year [7], providing increased experience of operating. The primary technology types of electrolyser are Alkaline, Proton Exchange Membrane (PEM), and Solid Oxide Electrolysers (SOE).

Alkaline electrolysers were the first commercially deployed electrolysers and have a proven track record for reliability and operational performance. Alkaline electrolysers use a liquid electrolyte. This liquid electrolyte increases the likelihood of leakage and maintenance requirements. This is easily manageable in local onshore environments, however for application in a remote offshore environment it brings an increased cost of electrolyte supply and well as an increased maintenance cost. The produced hydrogen may also include traces of electrolyte which requires removal prior to export. The liquid electrolyte has limited response to fluctuations in electrical inputs, which is an important consideration given that the Dolphyn project uses renewable energy from wind turbines which will have a variable electrical input. Operational pressures are usually limited in alkaline electrolysers to a maximum of around 30 bar requiring additional compression to enable export through long distance pipelines. [8]

Solid Oxide Electrolysers (SOE) have gained increasing attention with work ongoing in the academic community to develop their commercial readiness. Whilst the technology is considered to have potential, there remains a number of unanswered questions over the commercial viability of the technology. At this stage SOE do not offer a credible commercial option for this project, however technologies are emerging and SOE may prove to be an advantageous technology in the future.

Proton Electron Membrane (PEM) Electrolysers use a solid polymer electrolyte instead of the liquid electrolyte used in alkaline electrolysers. PEM electrolysers are commonly utilised in the generation of hydrogen for a variety of applications around the world providing confidence in the technology's readiness. The high purity of hydrogen produced (>99%) is appealing for fuel cells usage (e.g. transport vehicle refuelling stations). PEM electrolysers are able to operate with a rapid response to fluctuations in electrical input, such as those from renewable energy sources. The efficiency of conversion is expected to approach 70% in the timeline and scale considered by this project, with potential for efficiency to exceed 70% as the technology fully matures. The concept comparison included here has used a representative efficiency of 67% for all design options. PEM electrolysers have a smaller footprint than other electrolyser types and are therefore more suited to offshore use.

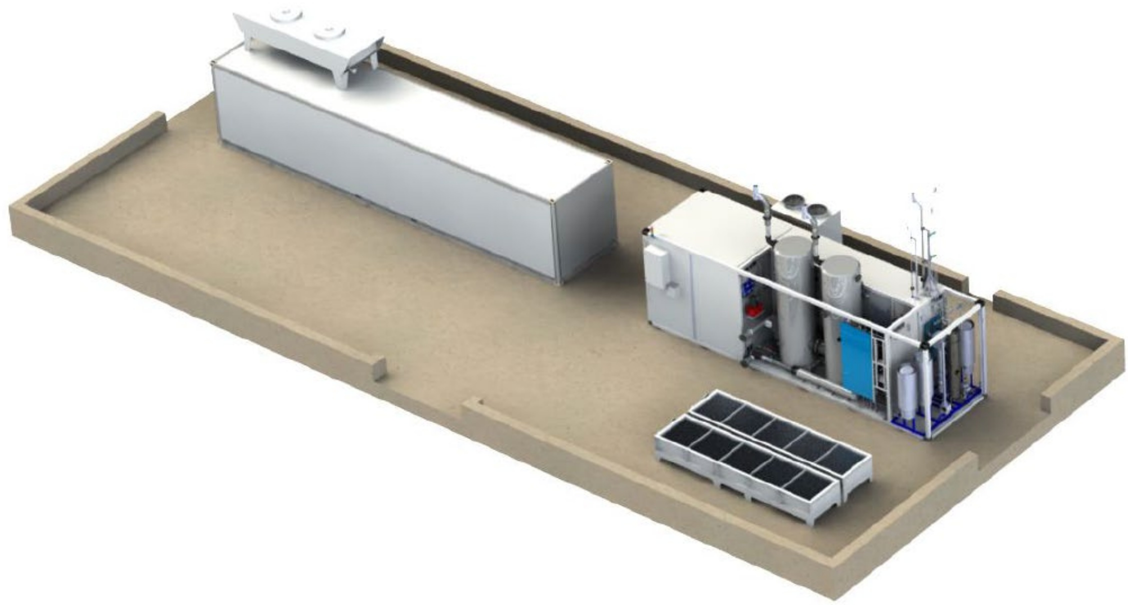
PEM electrolysers are able to operate at export pressures up to 30-50 bar. The remote nature of the Dolphyn project requires the export pressure to be sufficiently high to export to shore; increases in electrolysis operating pressures resulting in a decrease in requirements for an additional export compression system.

Electrolysis is a developing technology with a significant reduction in costs and increases in operational efficiency being realised recently. As scales of production increase and further operational knowledge is gained, performance is expected to rise further. The Dolphyn project at full scale would provide significant demand for electrolysers to generate material cost savings. One of the main contributors to the overall cost is the electrolyser stack which comprises precious metals. Improvements in catalyst technology could provide reduce costs of this component in the future. Reducing the frequency of stack replacements is a key development that can reduce the operational costs of electrolysers, with stack replacements expected to be required once every ten years now, an increase from 7 years only a few years ago. General maintenance requirements for PEM electrolysers are low with one site visit for equipment calibration per six months being the scheduled maintenance activity requirement.

Electrolysers are currently designed to operate in onshore conditions and are laid out in a horizontal orientation. The fundamental operation of a PEM electrolyser is not affected by the expected level of motion arising from an offshore environment, however additional work is required to verify ancillary equipment (e.g. fluid level gauges) is suitable for use in offshore environments. In the Spar sub-structure concept a redesign of the electrolyser would be required to enable operation in a vertical orientation.

PEM electrolysers contain sensitive equipment that requires protection from damaging environments. As well as ensuring the equipment is located outside of the splash zone, the electrolysis package will be provided with external cladding to provide additional protection. Electrolyser units are commonly delivered as a standalone package including water treatment and control system integration as shown in Figure 2.4. This standalone operation capability can bring simplicity to integration with other systems, however further system optimising may be gained by integrating with other systems. These potential optimisations are available during engineering design for all concepts under review and no such benefits have been taken into account for the sake of comparison.

Figure 2.4 PEM Electrolyser Equipment



REF: ITM [11]

PEM electrolysers are capable of rapid start-up and shut down. During periods of shut down some energy is required to maintain operation of essential systems and also to avoid freezing of the electrolysis systems. A supply of backup/standby power must be available during periods of shutdown.

For the reasons outlined above, PEM electrolysers are considered best suited for this project and are therefore taken forward for usage in the design concepts. Of particular importance in the technology selection process was the project requirement for electrolysers that are suited for variable electrical input from renewable energy sources. Additionally, one of the primary costs over the lifecycle of the project is the operations and maintenance costs, as the general maintenance requirements for PEM electrolysers are low this reduces the need for manual intervention in an offshore environment.

The use of electrolysers in the concepts considered for this project raises a number of design considerations. Hydrogen and oxygen are produced during the electrolysis process creating the potential for flammable atmospheres to form. The understanding and control of this hazard is essential. Beyond electrolysis systems, hydrogen has over a century of common usage in the chemical and oil and gas industries with both private companies and the UK regulator having significant experience of ensuring safe operation. Avoidance of hazardous atmospheres, control of ignition sources, and suitable overpressure relief are all taken into consideration in the electrolysis packages. The design concept that includes centralised hydrogen production, either infield or onshore (i.e. Cases 2 and 3), concentrate significant hydrogen production capacity in close proximity increasing the likelihood of an accident event shutting down the entire field production.

The electrolysis package is capable of taking and purifying potable water for use in the electrolyser. In an offshore environment the use of sea water is highly desirable requiring an additional desalination process to prepare the water for use in the electrolyser.

2.2.7 AC-DC Rectification

Wind turbine generators generate electricity with an alternating current whilst electrolysers require a direct current input, as such AC-DC rectification is required. Electrolysers are currently in use with electricity supplied from the AC UK transmission system, with AC-DC rectification included. No significant costs or challenges associated with AC-DC rectification were identified, and the requirement for rectification exists for all design concepts under consideration.

2.2.8 Desalination

A desalination unit is required to prepare seawater for use in the electrolyser. Its primary function is to remove salt and other impurities to enable a stable stream of consistent purity water to be supplied to the system, minimising downtime for unscheduled maintenance. The desalinated water requirements are modest in comparison to many current applications in ships or offshore oil and gas platforms. The design concept that includes a centralised offshore electrolysis function (i.e. Concept Case 2) will have a much higher requirement as it will need to supply the full field complement electrolysers.

Large quantities of concentrated brine can have an impact on aquatic environments. An advantage of the Dolphyn design (Concept Case 1) is the separation of desalination units for each floating sub-structure, reducing concentration of brine dispersal points. Early analysis indicates that brine dispersion from the Dolphyn design is unlikely to impact the local marine environment, however site specific current data will be reviewed as part of the environmental impact assessment to confirm this. The centralised electrolysis design concept (Concept Case 2) produces sufficient quantities of brine to impact the local environment if released without mitigation. This is a disadvantage of this option.

Onshore electrolysis (Concept Case 3) can use mains water supply providing a sufficient local source is available, alternatively a local desalination plant may be constructed if the site is located close to the coast.

There are a range of desalination technologies available and several are available and proven for operation in offshore environments. The leading technologies identified include reverse osmosis and thermal desalination due to the low operation and maintenance requirements and potential for heat recovery from the electrolysis unit respectively. The desalination unit is not a significant factor in the selection of the design concept and will therefore be finalised during FEED to allow for interfaces with other equipment items to be optimised. For comparative purposes thermal desalination units have been assumed for all design concepts.

2.2.9 Seawater Lift

Seawater lift pumps are used to generate a flow of seawater into the desalination unit. The total flow requirements is at the lower end of the range of flows currently used within the offshore oil and gas and shipping industries. The inlet for the seawater lift should be located sufficiently far below sea level to minimise the risk of aquatic flora inhibiting the flow of water through the filtration system. Maintenance requirements are below those necessary for normal operation of the wind turbine generator or electrolyser and largely limited to replacement of the filtration system. The seawater intakes should be at a suitable location to avoid significant quantities of brine being taken into the system. The Dolphyn concept is not expected to produce significant brine plumes and consequently brine uptake is considered to be easily avoided. The concept including centralised offshore electrolysis (concept Case 2) is expected to generate higher concentrations of brine in seawater. Avoidance of brine is possible, but would require consideration during the next design phase when detailed plume modelling will be available.

2.2.10 Risers and Gathering Manifold

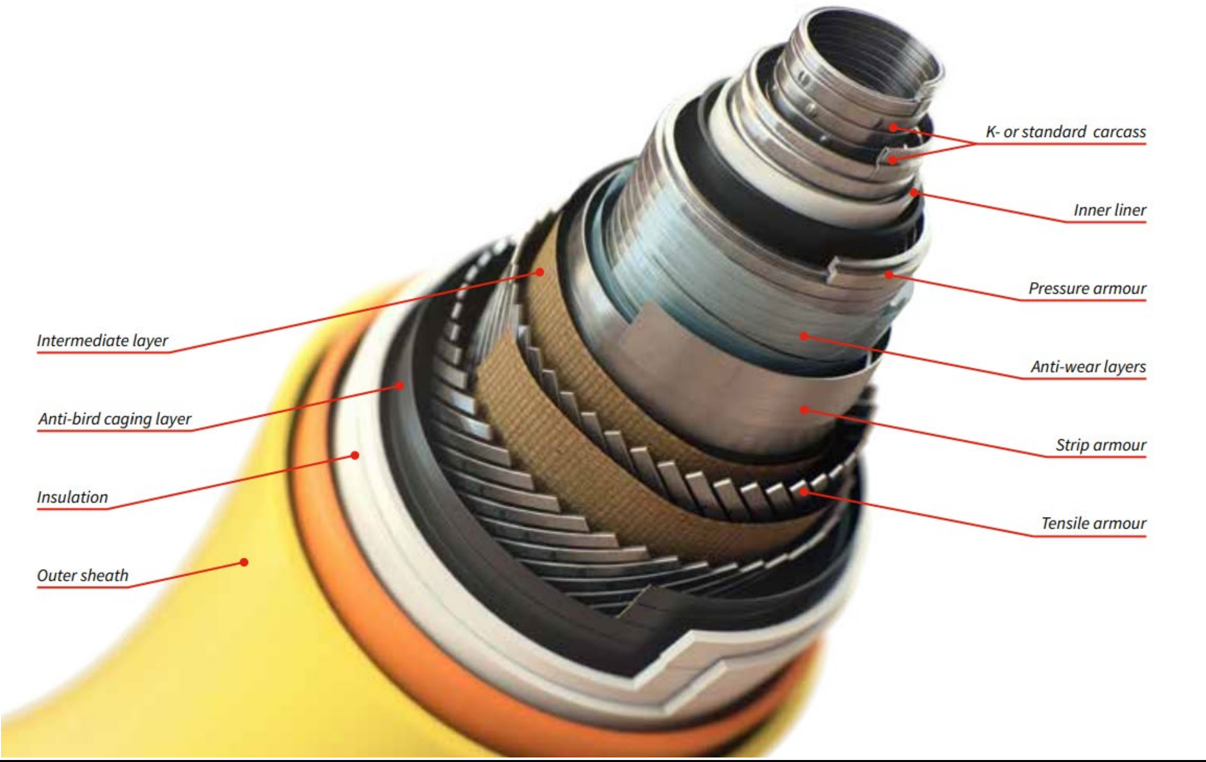
Risers are used across the oil and gas industry to transmit fluids from sea level to the seabed. Risers for fixed installations are often rigid, whilst for floating installations flexible risers are used. Flexible risers are available “off the shelf” in a variety of diameters (4” to 16”) and material specifications. Flexible risers can be either bonded, or un-bonded. Due to the relatively high mobility of the floating sub-structures un-bonded risers will be required. Bespoke risers can also be manufactured for use in unusual, original, or extreme environments. Flexible risers have been produced to accommodate high pressure, high temperature, corrosive, flammable, toxic, and acidic fluids.

Flexible risers have been designed and implemented for offshore gas operations at higher pressures and temperatures than those required for the Dolphyn project, therefore the anticipated process conditions are not considered to be a difficulty for vendors of flexible risers. Likewise fluids containing hydrogen have been successfully transmitted through flexible risers, however high purity hydrogen has not been a requirement to date. Vendors do not envisage any major concerns with developing flexible risers that are suitable for hydrogen duty. The material specification of the inner liner will be required to be suitable for hydrogen duty. A bespoke riser will need to be developed for Dolphyn but the cost is not expected to be significantly different to current costs applicable to the oil and gas industry.

Un-bonded flexible risers comprise a number of layers which are able to move independently to each other, enabling flexibility without excessively straining the materials. Each layer has a specific purpose from protecting against the inner fluid (e.g. corrosion), providing pressure containment, protecting from external impacts, supporting the weight of the riser, and providing insulation and protection from external corrosion. Not all layers are required for every riser design and specifications for use in the North Sea at the pressures and temperatures of interest are well understood. The inner most layer will be required to contain the hydrogen and will be the only layer expected to see hydrogen duty. This layer material will be specified to avoid hydrogen embrittlement from contact with high hydrogen purity fluid through material selection. Figure 2.5 shows a representative cross section of an un-bonded riser.

Flexible risers are connected to and supported by the floating sub-structure, much like the mooring chains. The weight of the riser and also the forces exerted on it by currents will be taken into account during the sub-structure design to ensure sufficient buoyancy is present. The flexible riser and mooring chains will be designed to avoid entanglement or impact on the sea floor which can lead to equipment damage or in extreme cases leaks from the riser itself. Flexible risers can be used in deep water, with an option of suspending directly between the floating sub-structure, without reaching the seabed if the water depth exceeds 1,000m. Buoyancy aids may be used to decrease the load taken by the sub-structure. All of these aspects are commonly addressed when using flexible risers in offshore oil and gas projects with no additional actions required to utilise them for any of the concepts considered.

Figure 2.5 Representative Cross Section of an Un-bonded Flexible Riser



NOV [10]

In the case of the Dolphyn concept, hydrogen will be transmitted from each floating turbine using a small diameter riser. Individual 10MW units can be linked using a single riser configuration for efficiency. The export from each bank of 10 turbines will be gathered using a sub-sea manifold into a series of intra field trunk lines, expected to be a medium diameter system. These trunk lines will end in a series of risers flowing into the floating export compression unit. A large diameter, main export riser will then transmit the hydrogen to a pipeline end manifold (PLEM) at the seabed. This manifold then connects to the main export pipeline.

2.2.11 Export Compression and Pipeline

For fields at long distances from shore, an export compression system will be required to deliver bulk hydrogen to shore through an export pipeline. Export compressors are currently used in the North Sea oil and gas industry to export natural gas from offshore installations to shore. Hydrogen is currently transmitted over long distances using export compression and pipelines with several thousand kilometres [6] of transmission piping in use around the world.

In order to ensure a constant flow of gas the pipeline needs to be pressurised and, because of resistance to this flow, a pressure drop is incurred. Various elements will affect the magnitude of the pressure drop including the diameter and length of the pipeline as well as the surface roughness of the pipe material. For the process to be as energy efficient as possible the pressure drop along the export pipeline needs to be minimised. It is, however, worth noting that experimental data has concluded that the pressure drop across varying lengths of hydrogen pipelines is relatively small compared to the pressure drop across natural gas pipelines [12].

One of the main challenges of transporting hydrogen is the potential for hydrogen embrittlement of the pipeline. Hydrogen embrittlement (HGE) is the process of hydrogen being absorbed into a material, reducing its toughness and ductility and making it more susceptible to damage. The effects of HGE is controlled by pipeline material selection. Some metals are vulnerable to HGE, but historically low-strength stainless steel and carbon steel have been used to transport hydrogen under normal operating conditions, however at higher pressures hydrogen embrittlement is promoted. Low-strength grades of steel are primarily used as they are more resistant to HGE than steels of higher strength. Polyethylene (PE) and polyvinylchloride (PVC) are already widely used for pipelines with experimental data showing no substantial change to the physical properties of thermoplastics when exposed to high-pressure hydrogen [13]. Should existing metal pipeline be advantageously located they can also be reinforced with polymers to protect them [15]. The high purity of hydrogen produced by electrolysis eliminates the potential for internal pipeline corrosion.

The requirements of the export compression system are driven by the expected pressure drop through the export pipeline. Accurate specification of the export compression system requires analysis of the location specific pipeline routing, however an indicative estimate of the export pressure drop through different pipe diameters over different distances has been conducted and no significant issues identified. It is possible that over shorter distances no export compression would be required provided the export pipeline was of a sufficiently large diameter.

Onshore hydrogen compression is proven primarily using reciprocating compressors at a significantly smaller scale than those proposed under this project. A total field export rate of around 1,000 tonnes per day is expected. Two of the largest reciprocating compressors that are commercially available would be capable of compressing the required volumes of hydrogen to an export pressure of >100 bar. The maintenance requirements for reciprocating compressors are relatively high making alternate solutions desirable.

Compression of large quantities of methane for export is typically achieved using centrifugal compressors. Centrifugal compressors are not widely used for hydrogen at present, although discussions with vendors indicates that there are no significant challenges with using centrifugal compressors for hydrogen duty. In the design concepts being considered the lowest cost source of energy to power the compressors will be electricity due to the nature of the project. Large scale centrifugal compressors will need electricity to power the compression system. The concepts that include offshore hydrogen compression have allowed for additional offshore floating turbines to provide operating power to the compressions system. The size and weight of centrifugal compressors can be accommodated in the deck space of a floating wind turbine.

The small molecules present in hydrogen will increase tendency for leakage, as such a high seal integrity confidence will be required. Prior to full field commercialisation demonstration of high leak integrity compressors, suitable for hydrogen duty, will be required if they have not already been completed.

2.2.12 Export Transmission Lines

If electrolysis activities are undertaken onshore rather than offshore (i.e. Concept Case 3), then export transmission cabling would be required to transport the electricity generated by the wind farm to the onshore electrolysis infrastructure. This technology is proven and commercially available, typically connecting the offshore and onshore substations for fixed bottom offshore wind farms.

Depending on the distance of the wind farm from the shore, it may be technically and economically preferable to install High Voltage Direct Current (HVDC) or High Voltage Alternating Current (HVAC) export cabling. AC export cabling is 3-core and generally rated around 132 kV – 245 kV, with 220 kV becoming typical, while HVDC has two single-core cables typically rated around 320 kV.

While HVAC cabling is relatively lighter and cheaper to install, power losses can become significant over longer distances as a result of reactive power flow. As a result HVDC may prove economically attractive if the cable route is long enough (around 100km or more), meaning that the relatively high cost of equipment and installation (for example converter stations) is offset by the savings from reduced losses.

For ERM's concept select analysis we have assumed that if the wind farm is 50km from the shore then a HVAC system is installed, and for 100km or 250km offshore a HVDC system is installed.

2.2.13 Inter-Array Cabling

If electrolysis activities are not undertaken at each WTG, and are instead undertaken on a centralised offshore platform or vessel, or onshore, then inter-array cabling would be required as part of the wind farm design.

This technology is proven and commercially available for fixed bottom offshore wind farms, connecting loops or strings of wind turbines to the offshore substation. Array cables at offshore wind farms are typically rated at 66 kV.

The use of floating rather than fixed bottom wind turbines would require the installation of dynamic inter-array cabling solutions, leveraging experience in the oil and gas industry. Efforts to develop dynamic cabling solutions are underway, with testing planned for example on small floating arrays as part of HyWind and WindFloat Atlantic [12].

2.2.14 Offshore Installations

In addition to the floating offshore wind turbines, some of the design concepts considered require additional offshore floating structures. An offshore electrolysis structure is required for the concept including centralised offshore electrolysis (Concept Case 2). The concept looking at onshore electrolysis (Concept Case 3) also requires an offshore substation. No additional structures are required for the Dolphyn design concept.

Offshore Electrolysis Installation (Concept Case 2)

The centralisation of electrolysis offshore requires a floating structure to house the electrolysis equipment, and export compression as well providing the option for storage of maintenance supplies. An offshore electrolysis structure also provides the option for having a permanently manned facility providing a faster response time for unplanned maintenance activities.

Hydrogen is highly flammable and collocating the electrolysers will increase the total inventory in a single location. Avoidance of leaks, ignition, and the spread of any fire will be critical to mitigating the risk of the loss of the facility. Unlike the distributed Dolphyn concept, the location of all field electrolysis in one location will increase the level of asset risk with this option (single point of failure that could halt production from the entire field).

The main driver for the selection and specification of the offshore electrolysis structure is the space requirement of the electrolysers. Whilst access for maintenance of the electrolyser will be required, as well as fire protection and bulk heads, there will be the ability to optimise the layout design to maintain this average volume per package.

A total of 4 GW of electrolysers will be required for a 20 x 20 array of 10MW units. Very Large Crude Carriers (VLCCs) are amongst the largest vessels commonly used worldwide with 7-8 decks required with a height exceeding 3 m per deck. More realistically this would require two vessels with 3-4 decks each. In the offshore oil and gas industry large FPSOs and FLNG vessels have been constructed and operated on this scale although the construction and operational costs are high.

Offshore Substation (Concept Case 3)

The design option which incorporates onshore electrolysis (Concept Case 3) requires an offshore substation to be included as part of the wind farm design. The offshore substation may be HVAC or HVDC, with the key driver being distance from shore when determining the most cost-effective solution. The sub-station would perform a number of functions including integrating the AC power output from individual turbines in the wind farm, transforming the voltage (for example from the 66kV output from the wind turbines to 275 kV for export to the onshore substation in the case of HVAC, or to 132 kV for input into HVDC system) and converting from AC to DC in the case of HVDC.

Offshore substations and associated infrastructure (for example AC converter stations) are proven technology which is commercially available from a number of established suppliers. HVDC is relatively new and there have been some teething issues around availability for example, however it is considered proven and no major design innovation is expected to be required as part of this project.

2.2.15 Onshore Buildings

The design option for onshore electrolysis (Concept Case 3) requires an onshore facility to house the reception substation and electrolysis. The facility is expected to be located on the coast to minimise the length of transmission lines and provide access to seawater should it be required.

The substation (either HVAC or HVDC) will be housed in a substation building, similar to those currently used in the power sector for long distance power transmission. The largest space requirements comes from the electrolysers. The hydrogen is flammable so separation of the electrolysis equipment to minimise the impact of any ignited leaks is desirable. The scale of the project is such that the facility is likely to be a site of significant national interest, potentially requiring armed protection. Electrolysis and electrical substations are both proven technologies at onshore locations.

2.2.16 Standby Power

In field power is supplied by an intermittent power source, electricity from wind turbine generation. A number of systems have been identified as requiring constant power to ensure safe operation, including; the turbine yaw control, active ballasting systems, trace heating of the electrolyser, safety critical systems, and all control and communication systems. Safety critical and emergency response systems are expected to be supplied with a separate uninterruptable power supply.

Operational management systems will be developed to ensure power is supplied during scheduled activities, e.g. power supply from a stand-by vessel. As such the stand-by power supply systems should be specified for unscheduled downtime. The most common cause of unscheduled downtime will be due to unfavourable weather conditions preventing power generation through the WTG.

A common solution to the supply of stand-by power in remote locations is the use of a diesel generator. However, as one of the key drivers of the project is to provide low carbon power, no options for the supply of stand-by power which produce carbon emission were considered.

2.3 Technology Comparison

A review was undertaken considering the advantages, challenges, and enabling works required to develop each design concept to full commercialisation. A detailed breakdown of the review on a system by system basis has been conducted with Table 2.2 providing a high level summary of requirements.

Table 2.2 Comparison of expected modification requirements

Concept Case	**Dolphyn (Semi-sub)**	**Dolphyn (Spar)**	**Centralised Electrolysis**	**Electrolysis Onshore**	**Fixed Bottom**
Key Equipment Items	Case 1a	Case 1b	Case 2	Case 3a	Sensitivity only
1. Wind Turbine Generator (WTG)	⊖	⊖	⊖	⊖	⊖
2. Sub-structure	⊖	⊖	⊖	⊖	⊖
3. Mooring and Anchors	⊖	⊖	⊖	⊖	N/A
4. Electrolysis	⊖	⊖	⊖	⊖	⊖
5. AC-DC Rectification	⊖	⊖	⊖	⊖	⊖
6. Desalination	⊖	⊖	⊖	⊖	⊖
7. Seawater Lift	⊖	⊖	⊖	⊖	⊖
8. Risers and Gathering	⊖	⊖	N/A	N/A	⊖
9. Export Compression and Pipeline	⊖	⊖	⊖	N/A	⊖
10. Inter-array Cabling	N/A	N/A	⊖	⊖	N/A
11. Export Transmission	N/A	N/A	N/A	⊖	N/A
12. Central offshore platform	N/A	N/A	⊖	N/A	N/A
13. Onshore Electrolysis Buildings	N/A	N/A	N/A	⊖	N/A
14. Stand-by Power	⊖	⊖	⊖	⊖	⊖

Ready and fully proven for application	⊖
Negligible modifications/minor adjustments required	⊖
Small modifications (<£1M) required	⊖
Significant modifications (>£1M) required	⊖
Requires further major development (not considered suitable currently)	⊖

3. COST COMPETITIVENESS

3.1 Cost modelling approach

To evaluate the economic case for each of the concept options identified in Section 2.1 a financial (cost) model was developed for each. The structure of the model was developed with the phased approach of the project in mind, in order to enable seamless development of the cost modelling into Phase 1B.

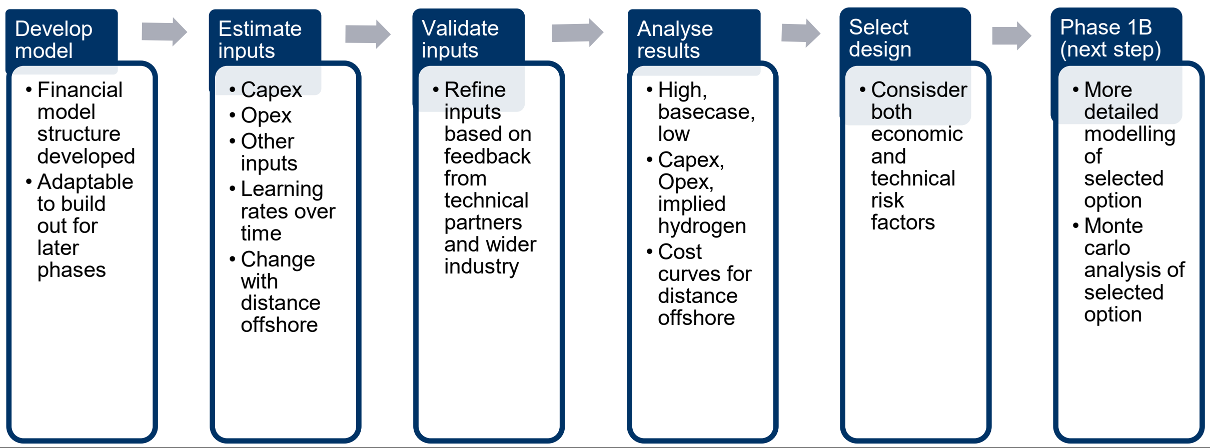
The Capex, Opex, Decex and other inputs for the model were developed by ERM based on industry research and discussion with manufacturers. These inputs and assumptions were then validated and refined based on feedback from wider industry including the technical subcontractors (Offshore Design Engineering (ODE) and Tractebel Engie) involved in Phase 1B of the project.

The initial results of the cost model were also sense checked against benchmark analysis for offshore floating wind [16].

The results of the cost modelling, and associated implied cost of hydrogen, were then used to develop recommendations for the selected design to be taken forward to Phase 1B, in conjunction with consideration of wider technical challenges and risks.

The modelling process is summarised below in Figure 3.1.

Figure 3.1 Cost modelling process



The key inputs and assumptions used in the cost modelling are outlined later in this Section. In summary, Section 3.2 presents the Capex assumptions, Section 3.3 the Opex, and Section 3.4 the Decex.

The modelling was undertaken based on a single 10MW wind turbine, within an assumed 20 x 20 field (i.e. 400 x 10MW turbines), leading to total installed capacity of the wind farm of 4GW. The construction schedule was considered constant for all options, with commissioning at the start of 2031.

As the focus of the analysis was on comparison of the technical design options, non-technical costs (such as project financing) were assumed to be constant, benchmark values. The focus of the cost modelling analysis was then on the technical assumptions to identify the most economically advantageous and technically feasible solution.

The design options considered in the cost modelling are summarised in Table 3.1 below:

Table 3.1 Design Options

Option ID	*Layout*	*Sub-structure*	*Distance offshore*
1A	ERM Dolphyn Concept: Offshore hydrogen production, with desalination and electrolysis integrated with floating wind turbine platform to enable local production of hydrogen and pipeline export.	Single spar	50km
2B			100km
3C			250km
4A		Semi sub	50km
5B			100km
6C			250km
7A	Desalination and electrolysis performed in field on a separate centralised offshore platform/vessel, with gas pipeline export to shore.	Conventional floating wind farm (assuming semi-sub design)	50km
8B			100km
9C			250km
10A	Onshore electrolysis and hydrogen production, using power cables to bring electricity back to shore.		50km
11B			100km
12C			250km
13A	Desalination and electrolysis integrated with fixed bottom wind turbine platform to enable local production of hydrogen and pipeline export.	Fixed bottom	50km
14B			100km
15E			20km

As can be seen from the above table, three offshore distances were considered for the floating wind analysis: 50km, 100km and 250km. Floating wind is expected to be utilised in deeper water, further offshore, and therefore 100 - 250km is considered closest to the most likely field locations. However, a range was modelled in order to build an understanding of the cost curve and compare with fixed bottom offshore wind. As 250km offshore would likely be in water depths which are technically unfeasible for fixed bottom solutions, a closer distance of 20km was included for the third case for the fixed bottom offshore wind analysis rather than 250km.

The role of fixed bottom offshore wind

Given the scale of green hydrogen production that would be required in order to decarbonise the UK's heating network and meet demand from other vectors such as shipping and trains, ERM considers that the majority of demand for green hydrogen would be met from floating rather than fixed bottom offshore wind. ERM's core analysis has therefore focussed on offshore floating wind, however three fixed bottom cases were considered in order to provide some context and comparison of the cost curve with distance offshore.

Key inputs, assumptions and sources used in the analysis are explained in each sub-section below.

3.2 Capital Costs

3.2.1 Modelling Approach

In order to model the Capex associated with each case, the potential costs were broken down into 22 elements. While most elements varied depending on the design option under consideration, some were considered constant for all cases, because even if the design varied there was not considered to be a material change to the cost of the Capex for the element, for example:

- Wind turbine
- Electrolysers

- Control system
- Desalination unit
- Project development and consenting
- Project management

Baseline (present day) costs for each element were derived from a variety of sources, as follows:

- Publically available reports
- ERM's experience of renewables/hydrogen projects
- ERM discussion with OEMs
- ERM discussion with wider industry, for example technical partners involved in Phase 1B

The baseline costs were translated into future costs by applying learning rates based on projected installed capacity for floating wind and historic fixed bottom offshore wind learning rates.

3.2.2 Key Assumptions and Sources

An overview of the assumptions and sources for the five most material Capex elements is provided in *Table 3.2* below. These elements together comprise up to 87% of Capex.

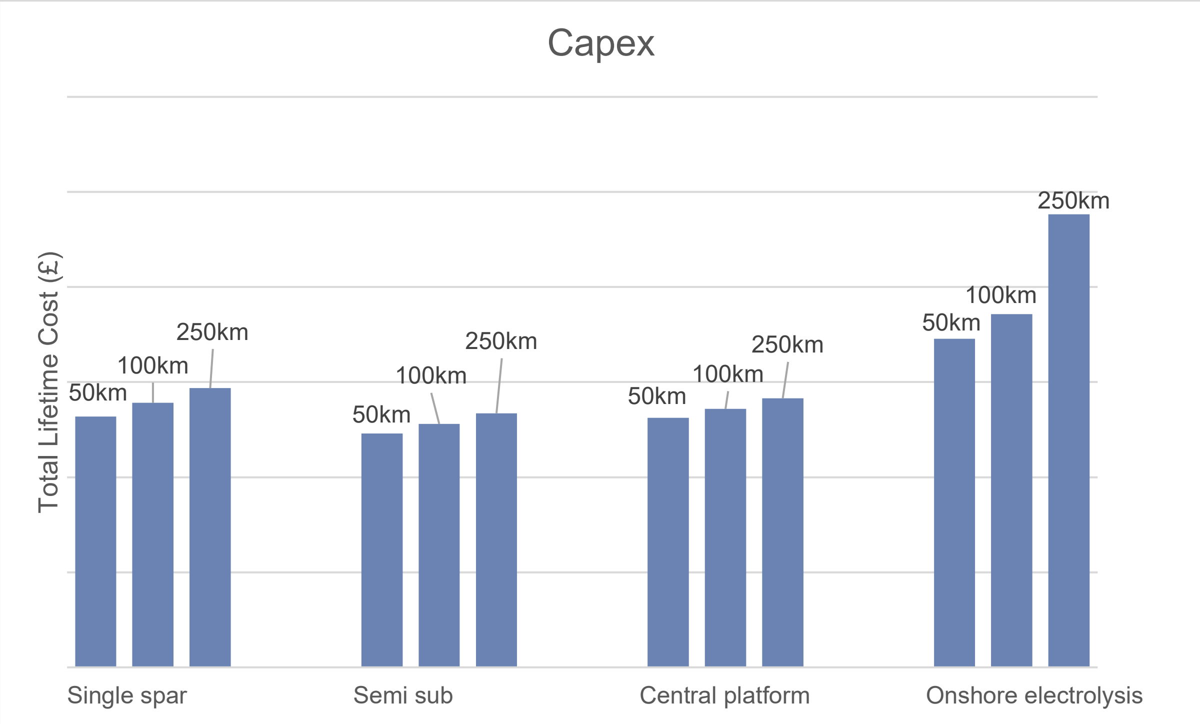
Table 3.2 Key Capex Assumptions and Sources

Case:	Single spar (Case 1a)	Semi sub (Case 1b)	Single centralised electrolysis platform (Case 2)	Onshore electrolysis (Case 3)	Fixed bottom
	1A, 2B, 3C	4A, 5B, 6C	7A, 8B, 9C	10A, 11B, 12C	13A, 14B, 15E
Floating sub-structure or fixed bottom foundation	Based on HyWind and including for the deck extension.	Estimated 40% price reduction by construction date (2030) based on discussion with OEM.	Floating turbines based on semi-sub design without modifications.		Based on industry benchmarks for foundation costs, with 20% [17] cost reduction by construction date (2030).
10MW Wind turbine	Based on 5% learning rate from historic offshore wind [18] applied to 2019 prices from BNEF [19] and industry reports [20].				
Electrolysers	Based on discussion with OEMs and industry research [21].				
Installation and commissioning of field	Spar installation Capex [22] plus non-turbine installation costs	Semi sub installation Capex [22] plus non-turbine installation costs based on technical partner industry knowledge.	Semi sub base-case with adjustment for single offshore platform.	Semi sub base-case	Based on industry benchmarks for fixed bottom offshore wind [23]
Mooring and anchors	3 x drag anchor mooring assumed, with costs from discussion with OEMs.				Zero as not required.

3.2.3 Capex Comparison

A comparison of the Capex for each case at the 3 distances offshore (50, 100 and 250km) is shown below in Figure 3.2 per 10MW unit. As can be seen, the semi sub option has lower Capex than the single spar, while the option to undertake all electrolysis onshore is associated with significantly higher Capex. Conducting electrolysis on a single centralised offshore platform demonstrates some economies of scale but is still a higher cost option than the Dolphyn semi-sub option.

Figure 3.2 Capex Comparison (per 10MW capacity)



Fixed Bottom Offshore Wind – Capex

The Capex associated with the fixed bottom offshore wind case for a 10MW unit varies for 20km offshore to 100km offshore. While fixed bottom costs appear lower than the floating options, it should be noted this solution would be unfeasible for the scale of generation required for the UK, which will require significant development in deeper waters. It also does not take account of longer term cost reductions that will arise as floating technology matures and de-risks.

3.3 Operating Costs

3.3.1 Modelling Approach

In order to model the Opex associated with each case, the potential costs were broken down into three elements:

- Opex for the wind farm
- Opex for the electrolysis and related equipment such as desalination
- The replacement of the electrolyser stack

Opex for the wind farm element was based on industry benchmarks and research, while Opex for the electrolysis elements was based largely on discussion with OEMs.

The baseline cost for wind farm Opex was translated into future costs by applying a learning rate based on projected installed capacity, while future Opex related to the electrolysers was based primarily on discussion with OEMs, sense checked against ERM's industry knowledge.

3.3.2 Key Assumptions and Sources

An overview of the assumptions and sources for the Opex elements is provided in Table 3.3 below.

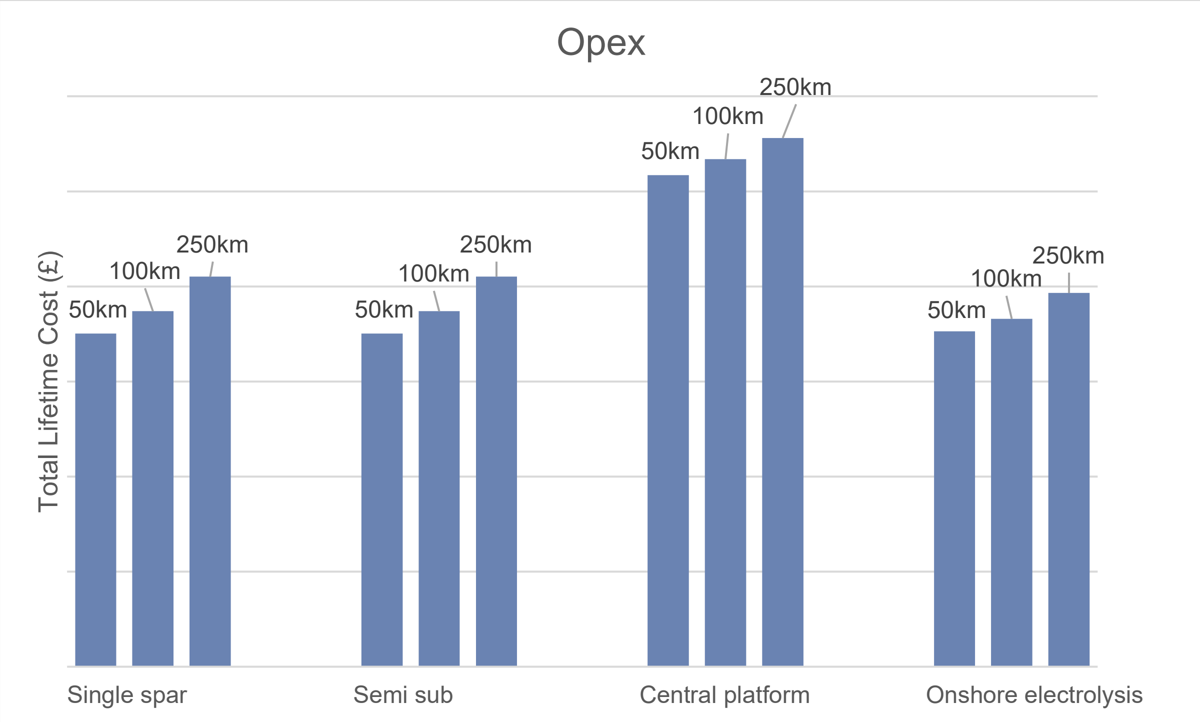
Table 3.3 Key Opex Assumptions and Sources

Case:	Single spar (Case 1a)	Semi sub (Case 1b)	Single centralised electrolysis platform (Case 2)	Onshore electrolysis (Case 3)	Fixed bottom
	1A, 2B, 3C	4A, 5B, 6C	7A, 8B, 9C	10A, 11B, 12C	13A, 14B, 15E
Opex for wind farm	Benchmark Opex per MW based on achieved European prices for fixed bottom [24] and projections of floating wind O&M [22]. 5% learning rate applied to translate 2019 costs to operational timeline, based on projections of impact of future innovation [25].			Includes maintenance for cabling and offshore substation.	Major component replacement entails higher vessel costs for jack-up barge
Opex for the electrolysis and related equipment	Based on 4 visits per year in CTV, following discussion with OEMs.		Based on 3x fully manned FPSO type vessels.	No vessel costs so the Opex for this element does not vary depending on the distance offshore of the wind farm.	Same as cases 1A-6C
Replacement of the electrolyser stack (every 10 years)	The source of these assumptions is discussion with electrolyser OEMs.				

3.3.3 Opex Comparison

A comparison of the Opex for each case at the 3 distances offshore (50, 100 and 250km) is shown below in Figure 3.3. As can be seen, the semi sub option (Case 1a) has slightly lower Opex than the single spar (Case 1b), while the option to undertake all electrolysis on a single centralised platform (Case 2) is associated with significantly higher Opex (due the need to run two large permanently manned vessels). Conducting electrolysis onshore is the cheapest option, reflecting the reduction of onshore labour costs compared to those offshore.

Figure 3.3 Opex Comparison (per 10MW capacity)



Fixed Bottom Offshore Wind – Opex

The Opex associated with the fixed bottom offshore wind cases varies from 20km offshore to 100km offshore, which is very similar to the single spar, semi sub and onshore electrolysis options. As discussed in Section 0, the fixed bottom and floating cases are not directly comparable, however the results of the analysis highlight the potential benefits of floating wind maintenance concepts, such as being able to tow a turbine to shore in the case a major refurbishment is required.

3.4 Decommissioning Costs

3.4.1 Modelling Approach and Assumptions

In order to model the Decex associated with each floating wind case, the key activities associated with decommissioning were broken down and costed with indicative vessel and labour rates.

These key activities include:

- Vessel: Transit to site, operations on site, and transit to shore
- Wind turbine dismantling
- Sub-structure dismantling

For the floating options, two types of vessels were envisaged to be used:

- Anchor handling tugs (AHTs)
- Diving support vessel (DSV)/ remotely operated vessel (ROV) to disconnect anchors and cablings.

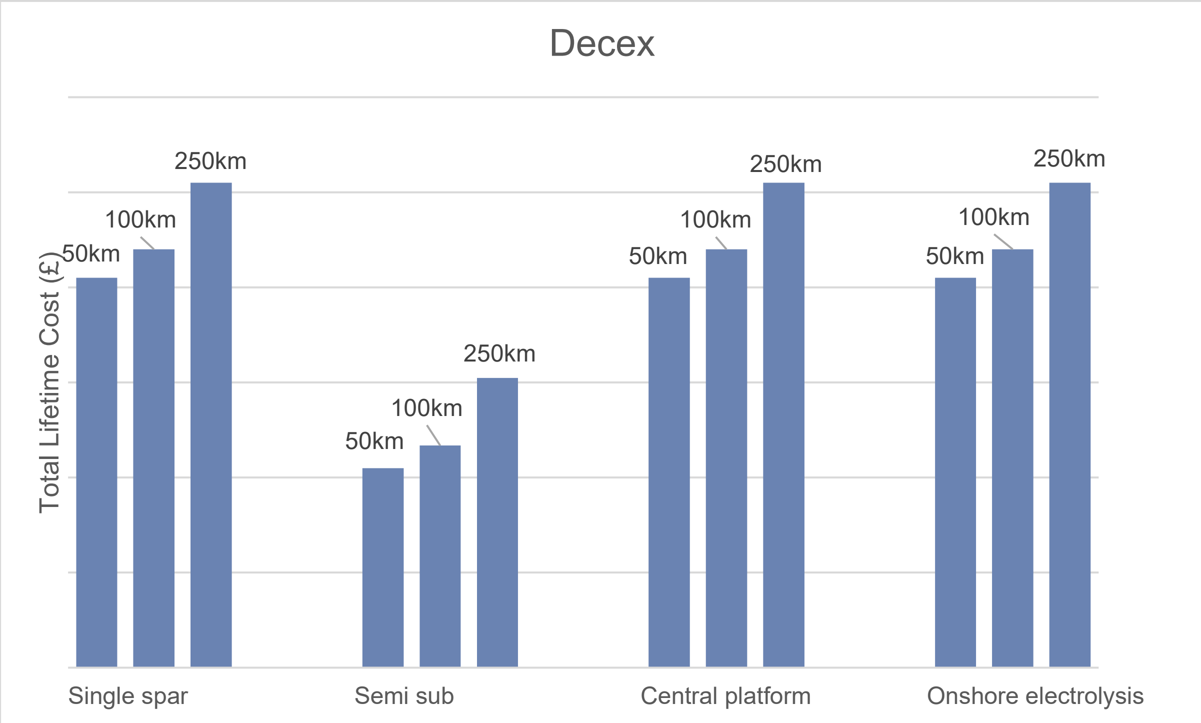
The wind turbine and sub-structure dismantling assumptions are based on industry quotes for wind turbine dismantling and industry benchmarks for large scale oil and gas decommissioning. An indicative scrap value was also used to offset part of the costs.

The Decex assumptions for the fixed bottom cases were based on established industry benchmarks from publically available research [26, 27, 28].

3.4.2 Decex Comparison

An overview of the Decex assumed for each case at the 3 distances offshore (50, 100 and 250km) is provided in Figure 3.4 below:

Figure 3.4 Decex Comparison (per 10MW capacity)



As can be seen above, costs increase with distance offshore, reflecting higher vessel costs. The decommissioning costs for the spar options are assumed to be higher than semi sub for several reasons:

- Scrap value is lower due to lower weight of sub-structure
- Heavy lift vessel assumed to be required to remove the turbine from top of the spar
- The spar might have to be re-floated horizontally to be dismantled/towed to dry dock (increasing AHT/DSV vessel time)

However the sub-structure dismantling cost onshore is assumed to be lower than semi-sub due to the lower weight.

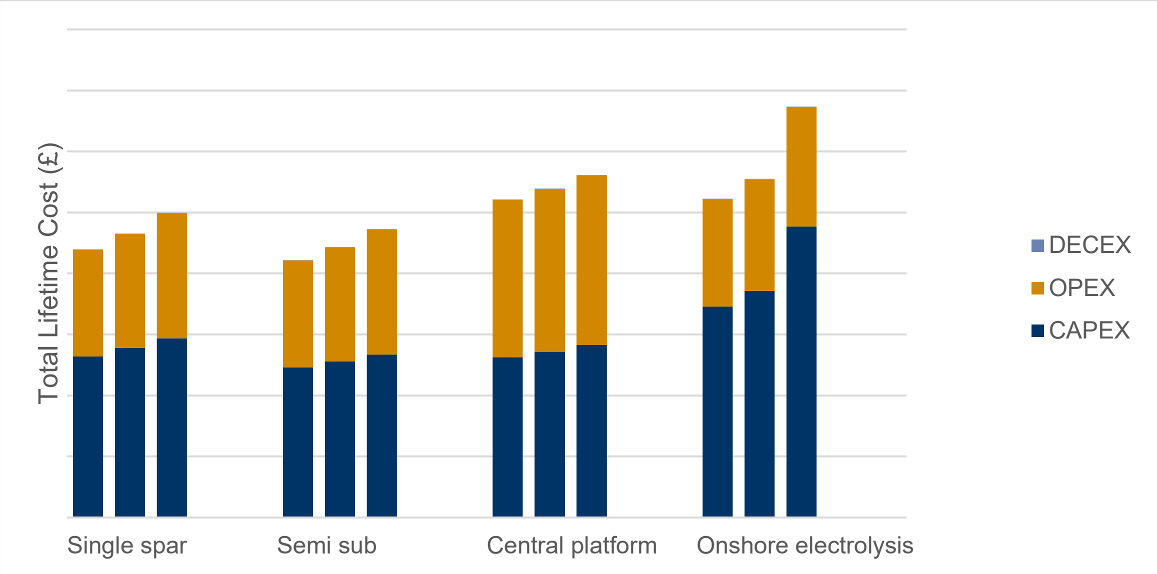
Fixed Bottom Offshore Wind – Decex

The Decex associated with the fixed bottom offshore wind cases varies for 20km offshore to 100km offshore, and is significantly more expensive than floating wind, reflecting higher vessel costs and decommissioning requirements associated with the foundations.

3.5 Concept Cost Comparison

A comparison of the floating wind lifetime costs is presented below in *Figure 3.5*.

Figure 3.5 Comparison of Floating Wind Lifetime Costs (per 10MW unit at 3 distances offshore (50, 100 and 250km))



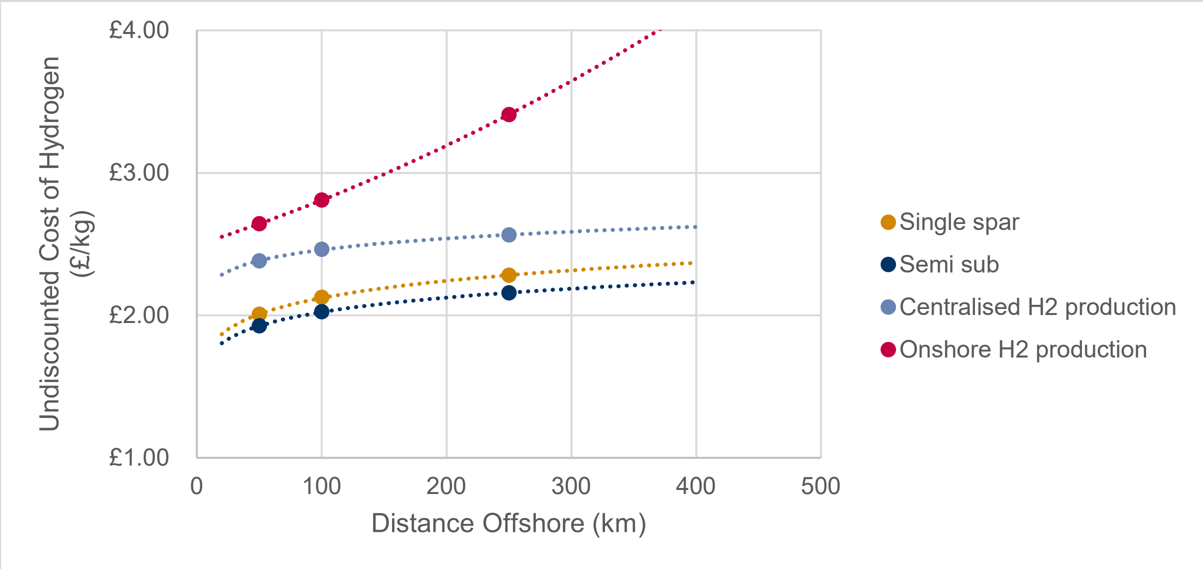
As can be seen above, the semi-sub provides the most cost-effective solution. Both the integrated spar and semi-sub design are preferable to the options where electrolysis takes place on a single offshore platform/vessel or onshore.

Fixed Bottom Offshore Wind – Lifetime costs

The lifetime costs associated with the fixed bottom offshore wind options considered in this analysis vary for 20km offshore to 100km offshore. This highlights the potential cost benefit to developing fixed bottom offshore wind at sites which are relatively close to shore (<50km), at least until floating wind costs fall to parity as the technology matures, construction and maintenance concepts develop and finance costs fall. As discussed in Section 1, large scale hydrogen demand for heating and transport will require more significant development of floating wind than could be met by fixed bottom sites alone, and this would be expected to drive cost reductions towards parity with fixed bottom.

The inclusion of indicative parameters for electricity generation and conversion to hydrogen allows calculation of the implied cost of hydrogen, as shown below in *Figure 3.6*. As would be expected from the cost assumptions outlined earlier in this section, the semi-sub option produces the lowest hydrogen cost, with the spar design next lowest. Onshore hydrogen production is the highest, reflecting the relatively high offshore electrical Capex and energy losses in particular compared with the other design options.

Figure 3.6 Implied Cost of Hydrogen



The results suggest the semi-sub is the preferred option from an economic perspective.

Fixed Bottom Offshore Wind – Implied cost of hydrogen

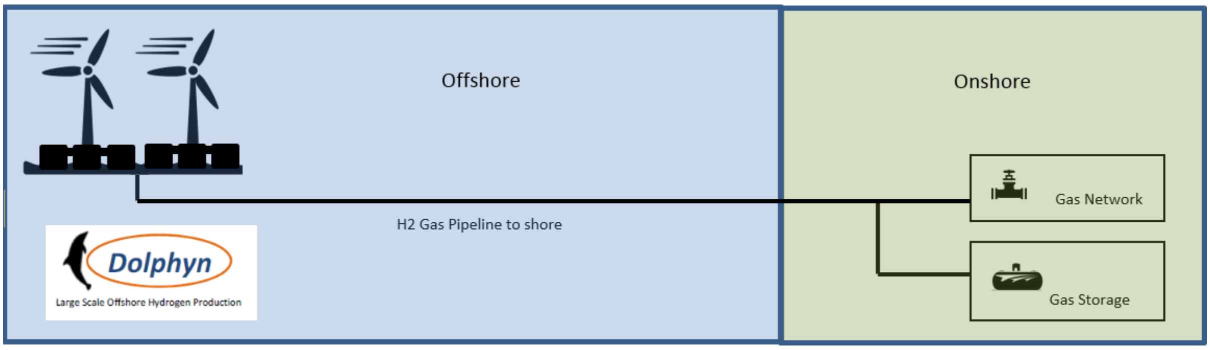
The implied cost of hydrogen associated with the fixed bottom offshore wind cases varies from around £1.77 for 20km offshore to £2.22 for 100km offshore, reflecting the lifetime costs outlined above. It should be noted that floating wind sites would be expected to achieve higher capacity factors than nearshore which would act to reduce the implied cost of hydrogen.

The economic analysis for the selected option will be refined further during Phase 1B and as the design develops further.

4. CONCEPT SELECTION

The technology review and cost analysis together enable a concept comparison, considering the likely works required to enable implementation and commercialisation. Each of the design concepts considered can technically be delivered by utilising existing technology, either directly or with modifications for the production of bulk scale hydrogen.

4.1 Case 1 (a and b) - Dolphyn Concepts



The Dolphyn design concept (Case 1a - Semi-sub option) provides the lowest cost production of hydrogen at all distances from the shore that were modelled for the 3 floating design concepts. It is also the most technically feasible option due to the large easily accessible area available to locate the topside equipment (electrolyser, desalination unit, etc.). The Dolphyn semi-sub option is therefore selected as the most suitable design which will now be forwarded to FEED under Phase 1b of the project.

The semi-submersible sub-structure offers the lowest overall cost due to its ability to incorporate a weather protected deck at a low cost of modification, and relatively low construction and installation cost due to the ability to install the turbine in port and tow to location. The relative challenge of creating sufficient deck space creates a constraint to using the spar type design for the Dolphyn project. However, the spar type design remains feasible and may prove to be advantageous in deployment environments outside of the range considered in this study, e.g. very deep water, or non-North Sea environments.

Electrolysis technology has developed sufficiently for maintenance and reliability requirements to be well understood and manageable in an offshore environment if certain design changes (e.g. re-designed level gauges to reduce sensitivity to offshore motion) are included. Enablement works are required to refine the instrumentation and control systems to achieve this and this is planned at detailed design stage when developing the first 2MW prototype.

Riser and pipeline technologies are well suited to the long distance, sub-sea transportation of energy (in the form of hydrogen). Design and testing activities will be carried out to prove the fitness of technology for pure hydrogen duty for flexible risers during the prototype detailed design phase of the project.

At a commercial level, the Dolphyn concept enables the field to be developed in a phased approach whereby production from the first turbines installed can begin whilst the rest of the field is developed incrementally, assuming that the export pipeline and associated infrastructure to connect to the gas grid/storage is available.

Export from multiple fields or from larger turbines can be accommodated using a larger pipeline. The relative price impact of larger capacity export equipment is not significant, indeed it is expected that further economies of scale will act as to reduce the overall unitary price of hydrogen.

Semi-Sub Design	
Pro's	Con's
• Large available deck space • Easy access for equipment installation in Port • Low installation cost • Tested in real world conditions • Sub-structure design available to project team • Known cost and delivery time • Can use existing electrolyser design	• Air gap needs to be increased • No grid connection so standby power required • Electrolyser response to offshore motion needs validation

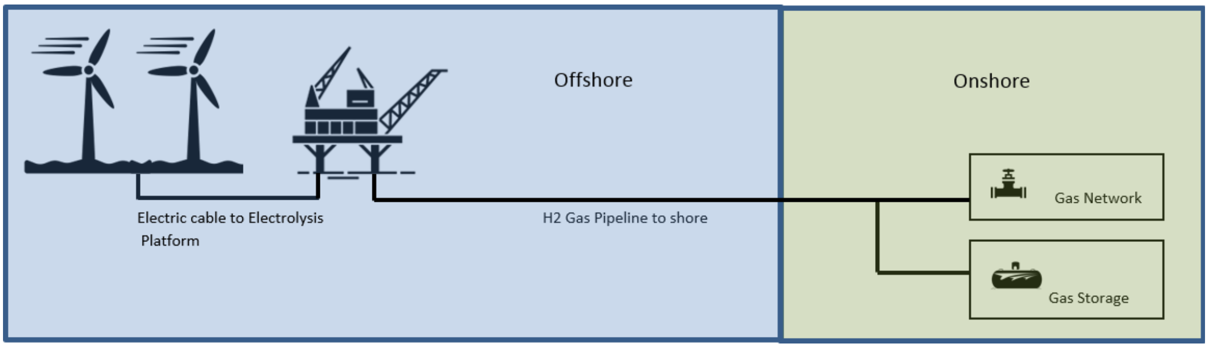
Spa Design	
Pro's	Con's
• Tested in real world conditions • Small footprint • Integrated design	• Deck design complicated • Difficult access for equipment installation • Requires offshore heavy lift vessel (high installation cost) • No grid connection so standby power required • Electrolyser need re-design for smaller footprint • Electrolyser motion response needs validation • Uncertain cost /pricing/delivery time

Fixed Bottom Offshore Wind

The use of fixed bottom offshore wind for the Dolphyn design concept eliminates the need for floating technology to be implemented, enabling more mature technology to be used at a reduced cost. However, the cost of fixed bottom installations increases with water depth. Shallow water locations around the UK tend to be closer to shore which is reflected in the cost comparison against the Dolphyn floating design options. Up to around 50 km from shore the fixed bottom design is the lowest cost means of production hydrogen. Above this distance, costs increase significantly as water depth increases

In practice fixed bottom installations close to shore may be limited by field size, with development of large arrays of 10 MW turbines unlikely within sight of the shore (and impacts on shipping lanes and sensitive coastal areas).

4.2 Case 2 - Centralised Offshore Electrolysis



The centralised offshore electrolysis design option provides an intermediate cost option across all distances.

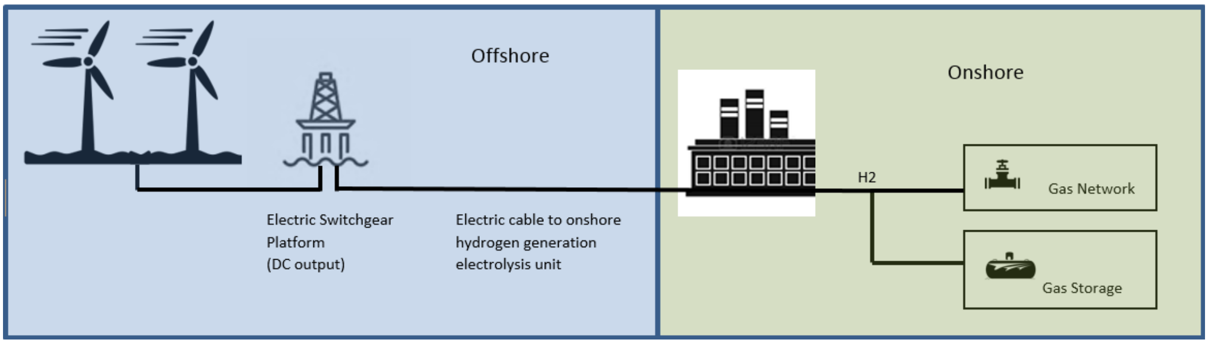
The deck area requirements for 4 GW capacity of electrolysers is significant, with two large FPSO type vessels being required to be moored in field. It is expected that such vessels would need to be developed in compliance with Class requirements specifically for the stated application. Whilst feasible, the cost of developing and permanently manning such a vessel is significant. The presence of a vessel in-field mandates a permanent manning philosophy. Permanent manning creates additional costs and logistical requirements but enables an increased response to unplanned activities and ability to store large items of ‘spare parts’ equipment in field.

Production from the field is dependent on the centralised platform being operational. The scheduling of maintenance activities will be optimised around the ability to continue production from the field as a whole. Electrolysers create a flammable gas (hydrogen) and the centralisation of all electrolysers in a single location creates an increased risk of an accident which could impact production from the entire field. The control of ignition of flammable gasses is well understood in the oil and gas industry, as is the ability to mitigate blast overpressure. However, a very high standard of design and operational control will be required given the vast amount of hazardous equipment that would be co-located under this option.

Export of hydrogen through pipelines enables the cost of hydrogen to be less sensitive to the distance offshore than for the onshore electrolysis (Case 3) concept.

Centralised H2 Production (with Semi-Sub design turbines)	
Pro’s	Con’s
• Reduced maintenance for individual turbines • Spares holding capacity for electrolysers • Rapid repair times • No requirement for sub-sea H2 gathering template	• Requires multiple VLCC sized offshore vessels with multi-decks to accommodate the electrolysers • Vessels require permanently manned crew • High CAPEX and OPEX • High asset risk due to all electrolysers in single location • High initial project cost • Difficult to design suitable prototype • Electrolysis response to offshore motion needs validation • Unknown ‘Class’ requirements

4.3 Case 3 - Centralised Onshore Electrolysis



Centralised onshore electrolysis provides the highest cost option for the development of hydrogen at all distances, with costs increasing with distance from shore.

The transmission of electricity over large distances creates a requirement for offshore and onshore substations. This is a challenge being addressed presently in the offshore wind sector, with HVAC utilised for distances of up to around 100 km from shore, and HVDC proposed beyond this to reduce energy losses. Both technologies incur losses through transmission, which increase with distance. The size of HVAC and HVDC substations is sufficient to require an offshore floating platform to be installed.

The onshore reception facilities will be sizeable and are expected to be designated as a strategically significant location requiring military presence. Land planning costs are highly location specific, but through a site selection process this cost can be managed. Development of large scale onshore production facilities is well understood and would likely fall under existing regulatory and planning requirements (e.g. COMAH).

Overall, this option suffers economically due to the high cost of the electrical equipment (Capex) needed offshore for the long distances likely to be involved in developing a field of GW size. This is compounded by the significant losses in bringing the energy back to shore via cable and switchgear rather than by pipeline. These two factors together impact the economic case for this option which worsens the further offshore the field is located.

Onshore H2 Production (with Semi-Sub design turbines)	
Pro's	Con's
• Grid connection enabling easy re-start and standby power • More closely parallels conventional floating wind development • Easier installation of electrolysis onshore - lower installation cost • Offshore turbine design fully tested in real world conditions • Electrolysis doesn't need validation for offshore motion • Can use existing electrolysis design	• Challenge scaling up to multiple fields • Emerging technology with difficulty gaining accurate costs • Cabling costs higher than pipelines • High cost of HVDC converters • Energy losses through electrical transmission • Consenting for large onshore hydrogen production facility (top tier COMAH?) • High overall costs due to electrical infrastructure at large distances offshore

4.4 Concept Selection Summary

A number of design options have been appraised both technically and financially and the following conclusions reached:

- Of the three different design configurations evaluated, the Dolphyn semi-sub design (Case 1a) has been identified as the most advantageous economic and technically feasible solution
- The selected concept is based on a proven semi-sub/ turbine combination with an arrangement that allows sufficient space for all of the topside equipment needed (including electrolysis, desalination and standby power equipment)
- The cost of 'green' hydrogen produced is expected to be broadly competitive with 'blue' hydrogen produced from methane reformation with carbon capture and storage (CCS) and could reduce further when the benefit of using 12MW and 15MW turbines is evaluated (discussed in Section 6)
- The following key activities have been identified as being important for the next Phase (Phase 2a – Detailed Design) stage of the project:
  - Electrolyser level gauges modification (if needed) and testing to ensure adequate performance under simulated offshore motion conditions
  - Identification of suitable port facility for construction of the 2 MW Dolphyn prototype
  - Identification of suitable location for operation of the 2MW prototype
  - Close working with similar projects and leading research to avoid duplication of efforts

5. DESIGN APPROACH

The primary objective of the front end engineering design (FEED) is to develop the selected concept design to a sufficient level to de-risk the project; providing confidence in the technical and financial viability of the project. It involved more than 30 engineering studies and resulted in a full set of engineering drawings of the design including Process Flow Diagrams (PFD's), Piping and Instrumentation Diagrams (P&ID's) and layouts. The technical aspects associated with key equipment items have been identified and a cohesive integrated design has been developed. Key parameters and aspects of the design are highlighted in this section.

5.1 Project drivers

As the complexity of the design increases a set of project drivers are increasingly useful to enable decentralised decision making.

Cost Drivers

The main cost driver for the prototype design is the produced cost of hydrogen for the commercial scale development (10MW+). £1.90/kg H2 is an initial estimate, with <£1.50/kg H2 as a target. The cost of production from the 2MW prototype is of secondary importance but is targeted to be below around £ 6/kg H2. The current hydrogen market is taken to be around £8/kg, demonstration within this level is important.

Accuracy of Cost Estimate

The 2MW prototype seeks to remove major unknowns in cost estimates and to ensure all items of technology are identified with design variations clearly understood.

The focus for the FEED stage is on "big-ticket" items (e.g. semi-sub overall dimensions, decks, key items of equipment). There is less focus on small details that will not impact the overall cost and final design. These will be addressed in the detailed design phase of the project (Phase 2a).

Ease of Operability / Maintainability

The prototype will be a key demonstrator for operating requirements (i.e. de-risk the OPEX for the full field development). The commercial scale development will be normally unmanned and fully autonomous.

There is not expected to be a dedicated support vessel for the prototype. The commercial scale project will be unmanned with minimum maintenance expected, which shall be demonstrated in the prototype. Operation and testing of the 2MW prototype will allow the fully autonomous control system for the commercial scale project to be defined and calibrated with confidence.

Proof of Systems and Novelty

The demonstrator project is required to prove all main systems for deployment on a full-scale unit. The prototype must be delivered and operational in 2-3 years.

The only novel sub-systems for the demonstrator should be those we are seeking to demonstrate, with a minimum number of variations to currently proven applications. Design systems will be modular and operate largely independently.

The technology will be tested, proven, and the operational characteristics of real life scenarios understood at the 2MW scale. Novel approaches to combining these proven technologies will be explored at the commercial scale with an emphasis on bringing further production efficiency and cost benefits.

Vendor engagement

Large numbers of potential suppliers have been identified and engaged during Phase 1. It is important to the project that the supply chain are actively engaged, participating and developing their designs to suit the offshore location and normally unmanned philosophy.

Procurement activities must show good value for money (for example through competitive tender for high value items), as well as compliance with both local and international law, and ERM's policies on ethics, bribery and corruption.

Emissions

The Dolphyn project is fundamentally predicated on its ability to reduce the level of UK greenhouse gas emissions. It must not produce any greenhouse gases emissions including carbon dioxide directly e.g. as a part of normal operations.

5.2 Design Basis

Hydrogen is a clean fuel, when it burns the only by-product is water. Therefore, hydrogen fuel is an attractive option to replace fossil-based fuels providing it can be shown to be safe, deliver comparable end-user performance and be economically viable. Hydrogen does not naturally exist in its elemental form and the production of hydrogen requires energy. To produce 'green' hydrogen, the energy used must be from a renewable source.

For the Dolphyn project hydrogen will be produced from two primary and unlimited resources:

1. Wind (kinetic) energy, converted into electricity in the generator of the wind turbine
2. Seawater, which is filtered, desalination and decomposed into molecular oxygen and molecular hydrogen (by electrolysis).

This project aims to develop a clean and economically attractive hydrogen production and energy storage application, with zero-carbon power sources.

Location

The scope of this phase of the Dolphyn project includes all topsides equipment and the substructure of the system. A representative (provisional) location on the east coast of Scotland is assumed for the Dolphyn project prototype for development purposes.

Constructability

The floater, the topside deck structures and the facility modules are designed to be fabricated on land as separate units in specialist yards (e.g. a shipyard for the floater versus a module fabrication yard for the topside). The decks and facility modules are designed to be lifted onto the floater as a single integrated topside or as separate pre-outfitted modular units

At the final outfitting yard, the floater, deck structures and facility modules will be hooked up and harbour acceptance tests (HAT) performed at the quayside before the sail away to the installation site. The mooring lines are pre-laid and laid down on the seabed for recovery during hook-up stage.

The basis is for a modular topside arranged and designed to be adaptable and scalable in order to fast track next prototyping phases (e.g. the 10MW variant).

Some of the principles applied to reduce the time and cost of construction are:

- Subdivision into large components and modules to fabricate the major components in the best location under the best conditions applicable to each component (e.g. sub-assembly sizing is linked to spray paint booth capacity)
- Simplification of the configurations and standardization of details, grades and sizes. Avoidance of tight tolerances provides inherent flexibility in the design.

- On-module outfitting to allow for flexibility in delivery of long lead items to their respective assembly sites

Modular design

The design has been split into discrete modules to simplify the design interface requirements, reduce the requirements for novelty and thereby reduce risk during operations. The primary modules are:

- Floating substructure
- Wind Turbine Generator (WTG)
- Mooring and Anchoring
- Topside structure

The topside equipment is also designed in a modular approach to provide a number of production and life support systems such as:

- Hydrogen production (including electrolyser)
- Export riser
- Desalination
- Power generation
- Power distribution
- Auxiliary systems
- Facilities

Codes and Standards

The engineering design has been developed following UK legislation and internationally recognised codes and standards. In the event of a conflict between the various referenced specifications and documents, the most stringent has been applied with the following decreasing order of precedence:

- UK Legislation and Regulations
- Dolphyn Basis of Design
- Dolphyn procedures and specifications
- Internationally recognised codes and standards
- Good engineering practice

Design Cases

The design is based on a number of representative reference cases to ensure the design is able to operate in a variety of conceivable situations. The design cases include normal operations during both winter and summer operating conditions. In addition a number of conceivable reduced WTG output conditions have been considered, including:

- Full generation (max H2 production rate)
- Turndown (reduced H2 production)
- ECO mode (intermitted H2 production)
- Desalination operation only (with no H2 production)
- Full standby with low power supply
- Full standby with no power supply
- Emergency shutdown

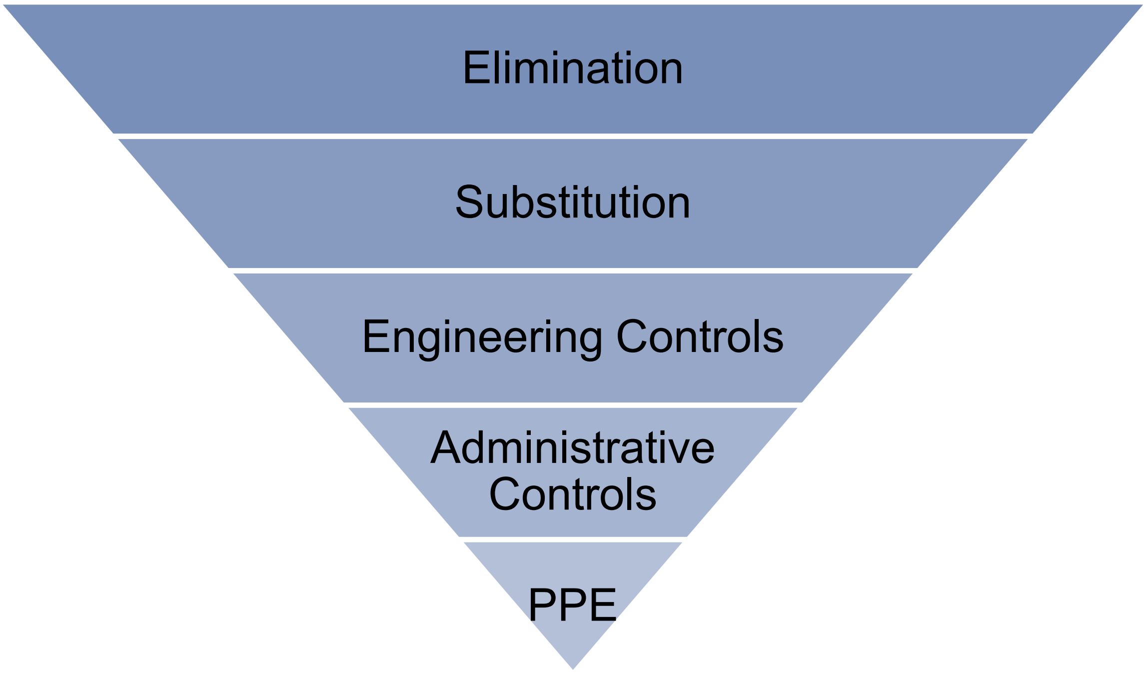
Safety Philosophy

The primary safety objective for the engineering design of the Dolphyn 2MW prototype is to minimise the possibility of injury to personnel from major accidental events. The key safety objectives to be addressed are:

- The design shall comply with all relevant UK legislation
- The design shall be such that all risks to personnel are identified and reduced to ALARP

The design will be conducted in line with the intent of the Offshore Oil and Gas Safety Regulations (SCR15) [30]. The design of the platform shall be focussed on an inherently safe design adhering to the hierarchy of controls outlined in *Figure 5.1*.

Figure 5.1 Hierarchy of Controls



The focus during the FEED stage is to eliminate, and substitute/reduce hazardous material where practicable. The practicality of engineering controls will also be considered. To support achieving this objective, safety design review workshops (HAZID and HAZOP) were conducted. The workshops were attended by a multi-disciplinary team of project engineers from ODE, Tractebel Engie and ERM.

Hydrogen Service Equipment

All materials selected have been specified for hydrogen service. A materials specialist has been involved in the design and compatibility of the hydrogen system. The main areas of concern for hydrogen are:

- Hydrogen embrittlement – hydrogen penetration in the metal resulting in increased brittleness and decreased tensile strength
- Hydrogen attack – atomic hydrogen diffusing in the metal resulting in localised deformation
- Hydrogen blistering – at high pressure hydrogen interacting with a constituent of an alloy

Materials are selected based on operating temperature and hydrogen partial pressure, more details can be found from Professional Association publications such as the American Petroleum Institute [31] and American Society of Mechanical Engineers [32].

Platform Access

The platform is designed for access in two ways; crew transfer vessel (CTV) and Walk to Work (W2W).

For regular inspection and maintenance campaigns of limited scope access by crew transfer vessel (CTV) is foreseen. Two traditional column-supported boat landings with ladder access to the columns are provided. The ladders shall be fitted with a fall prevention system. Two davit cranes are provided next to the boat landings for lifting of small loads from the CTV.

For more extended visits, or when less favourable weather conditions need to be overcome, a supply vessel can be used which is fitted with a walk-to-work motion compensated gangway system engaging directly to the deck on top of the column. Larger loads can be lifted off these vessels with the 3D crane on the attending vessel.

Unwanted access of the platform shall be prevented by fencing off the boat landing access way at the deck entry. If circumstances require, mariners in distress can access the platform via the boat landing up to the fence on the deck where a telephone will provided for making a distress call.

Control Philosophy

The Dolphyn prototype is designed to operate as an unmanned platform, which can be controlled from start up to hydrogen generation to shutdown, with turndown operations due to the operational peaks and troughs of the WTG. The prototype system is designed for full automation between generation phase and standby mode as it is designed to be not normally attended by personnel. This is inherently safer and minimises operation costs.

For the Dolphyn prototype unit, data communications will be from a single installation to the shore, whereas for the full-scale wind farm there may be a central hub from which communications are relayed to the shore. The wind farm may require different communication means intra-array and array-to-shore.

Chemical Injection

The Dolphyn prototype is intended to be operable remotely and to require minimum manned intervention.

The chemical injection package will include tanks, pumps, and instrumentation to meet the requirements for minimum manned intervention.

Waste Handling

There will be no permanent waste storage facilities on the platform. Bins for dry nontoxic and non-emitting waste are provided. Containers for wet, toxic and emitting waste shall be used during special operation and maintenance activities.

When the platform is left, all waste shall be collected and brought to shore for controlled disposal.

Drains

The collection of materials hazardous to personnel, contaminated wastewater and other fluid will be essential for all facilities in order to prevent pollution and the uncontrolled spread of fire risk. Process equipment that is susceptible to leakage such as pumps, filters, samples points shall be provided with drip pans/bunds to collect minor losses.

5.3 Quality Assurance

Due to the highly innovative nature of the project, appropriately experienced contractors are critical to the technical quality of the delivery. ERM, ODE and Tractebel provide sufficient combined experience of working within the floating wind and floating offshore oil and gas sectors to ensure confidence in the design. Specialist vendors are involved with the design as required to provide expert advice.

Documents produced as part of the design go through a quality assurance process to ensure they are suitable for use in the design. ERM, ODE and Tractebel each have an internal review process to ensure the quality of their respective deliverables. ERM have independently reviewed all deliverables prior to approval for use in the design.

Documents issued for review that have gone through the above review process, were reviewed and comments raised in a structured, consistent, and transparent manner.

In order to ensure quality is maintained, all information transferred to different parties throughout the project is tracked and recorded in line with the project document control procedure. This involved:

- Management and control of security of the documents by all party document controllers
- ERM Master Document Register
- Process for unique number of ERM documents and data
- Use of SharePoint to upload and store documents with comments and final documents issued for design

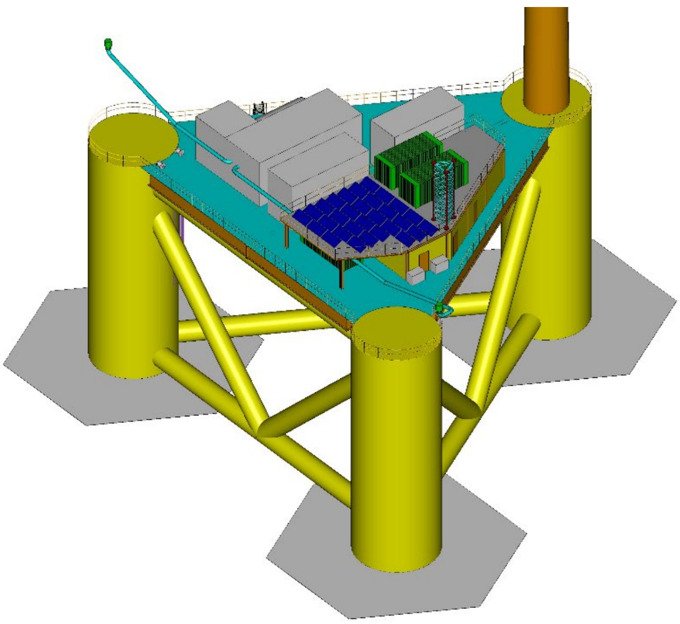
At key milestones of the project, interdisciplinary review workshops were conducted to ensure input and consistency from a wide range of specialties and experiences to identify potential project risks early. The key design review workshops were conducted by an independent chair to retain focus and movement through the design.

Maintaining knowledge between different phases of the project is critical to ensuring an efficient delivery. All identified open actions that are to be carried over into the next phase of the project have been logged in an 'Action Tracking Register' for clarity.

5.4 Key Design Outputs

The front-end engineering design has been completed for the 2MW prototype. A full design pack has been developed for all significant aspects of the design. The design has been developed in sufficient detail to de-risk the project moving forward into the next phase of development with a high confidence in the scope and effort required to reach the point where a final investment decision can be made.

Figure 5.2 3D Visualisation



5.5 Opportunities

The FEED stage of the project has been focussed on developing the high level scope to a sufficient level of detail to enable detailed engineering to be conducted with confidence. In addition to the workscope for the FEED studies a number of additional potential opportunities for the project were identified.

The following opportunities are presented at the end of the FEED project phase. Whilst not all of these opportunities are likely to be taken forwards, they offer benefits which will be reviewed by the project partners and other stakeholders. Some opportunities require further study or analysis, and potentially up-front investment to enable them to be considered within the scheme, or present opportunities for alternate projects:

1. Remove the existing hydrogen buffer tank and replace with pipeline pressure management to feed gas to the platform from the pipeline during shutdown periods (reverse flow could be enabled by adding a small valve, Emergency Shut Down Valve and metering).
2. It may be possibly to further reduce the design pressure across the seawater handling system in order to minimise the containment costs.
3. Hydrogen tank could be “wet” and then this allows rapid depressurisation through the export line via pump (filling tank with pressurised fresh water to displace hydrogen). Would require interfacing with multiple packages (e.g. electrolysis package, export riser design implications) but would improve the inherent safety.
4. The detailed design should include consideration of hydrogen service isolations provisions, where these might be required to isolate hydrogen containing equipment, rather than depressurising the hydrogen. This may be more pertinent for the 10MW system but will also be needed to isolate the 2MW prototype from the export flowline, which is assumed not to be depressurised for attendance to the facility for maintenance and monitoring.
5. Barge double block and bleed (DBB) connection at pontoon or boat landing is an option for start-up. This will allow connection to hydrogen powered ships, using same connection as hydrogen vehicles at gas stations. Electrolysis manufacturers have experience of this.
6. The oxygen provided by the 2MW unit could be used in a subsequent test series once the hydrogen production trials are complete. There are a number of schemes at present to sequester carbon by stimulating algae or seaweed growth via nutrient enrichment (generally in more tropical waters). However, drawbacks with these schemes are the oxygen deficiency which they may produce, and oxygen enrichment may be needed. Dolphyn, as an offshore oxygen generator could be re-purposed as a scientific demonstrator for such a scheme, to enable tangible carbon sequestration potential to be quantified in the field, by measurement of seaweed mass generated. As this would offer a further value stream for the oxygen produced, it is considered worthwhile to investigate this possibility with teams who are launching such schemes. It is also noted that the Dolphyn system could also power and carry the nutrient enrichment pumping systems (sourcing nutrients from the seabed) that this type of concept requires. [33]
7. Variable speed drives VSDs may offer energy savings. These saving would need to be considered inline with CAPEX savings which could be achieved as well as in conjunction with any tax benefits or grants which might apply to selection of energy saving devices. Analysis work could be conducted to understand interface details for power and gas management, given the system sizes suggested during the FEED stage.

5.6 Commercial Scale Concept Amendments

The current project is focussed on the development of a 2MW scale prototype. During the development of the 2MW prototype consideration is made to the likely amendments and efficiency benefits for the development of the commercial scale design.

6. FINANCIAL MODELLING

This section summarises the key financial modelling assumptions and inputs used to understand lifetime costs and equivalent cost of the hydrogen produced. These were obtained from a technical and financial review carried out during Phase 1 involving a wide range of industry sources and manufacturers of key equipment.

Two financial models have been developed in order to further investigate and understand the lifetime costs of the proposed solution:

- "Prototype Model" – Detailed financial model of a single unit 2MW prototype, including detailed cost modelling and Monte Carlo analysis.
- "Commercial Model" – Including more detailed modelling of a full scale commercial stage project, involving an offshore hydrogen wind farm comprising a 20 x 20 array of 10MW turbines. This was used to investigate drivers of financial metrics including NPV and IRR.

The models were built with sufficient flexibility to investigate how lifetime costs might change under a number of options.

6.1 Dolphyn Demonstrator Project ("Prototype Model")

Project lifetime

The basecase prototype model assumed a 25 year lifetime, however the model also considered a range of lifetimes from 5 years. The reduction in Capex and Opex was minimal for the lower lifetimes as the design basis is 25 years.

Resale value

The basecase lifetime of 25 years included no resale value for the wind turbine and substructure other than scrap value to offset the decommissioning cost. However if the prototype is operational for a shorter lifetime then additional resale value was considered realistic based on online market places and research, with the value stepping down over time, for example from £5.7m to £3.3m for a lifetime between 1-9 years. Example sources include online marketplaces for second hand turbines [34] [35].

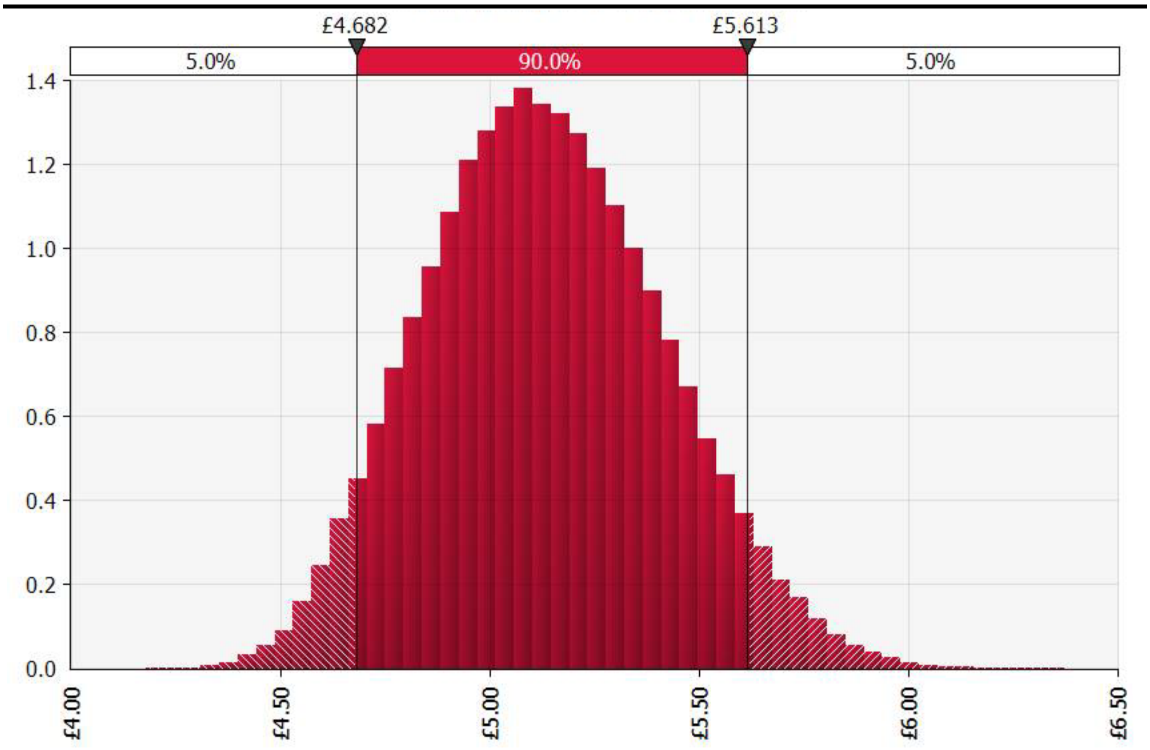
Monte Carlo analysis

As would be expected for this stage of the project, many of the financial modelling inputs have uncertainty associated with them, in particular elements of the cost estimates and performance drivers such as capacity factor and conversion efficiency of electricity to hydrogen.

In order to analyse and understand the key drivers of the project lifetime costs and implied cost of hydrogen, Monte Carlo analysis was undertaken in addition to the basecase financial modelling. Probability distributions were applied to the modelling inputs and then thousands of simulations were run in order to understand the potential range of the key outcomes of the financial model, and the likelihood that these might occur.

The results of the Monte Carlo simulation are summarised in *Figure 6.1* below. *Figure 6.1* demonstrates the potential variation of the implied hydrogen cost as the inputs vary.

Figure 6.1 Hydrogen Price Undiscounted (Prototype Model)



6.2 Dolphyn full scale 4GW commercial wind farm project ("Commercial Model")

Wind turbine size

The base case assumed a 10MW wind turbine size, however the financial model also investigated the difference in lifetime costs for 12MW and 15MW.

- If the WTG size was adjusted to 12MW then the associated wind farm Capex (for the whole wind farm) **reduced 8%**, and the associated annual Opex (for the whole wind farm, excluding electrolyser stack replacement) **reduced 8%**. The implied hydrogen cost therefore reduced from £1.93/kg to **£1.79/kg** (undiscounted).
- If the WTG size was adjusted to 15MW then the associated Capex **reduced 15%**, and the associated annual Opex (for the whole wind farm, excluding electrolyser stack replacement) **reduced 17%**. The implied hydrogen cost therefore reduced to **£1.65/kg** (undiscounted).

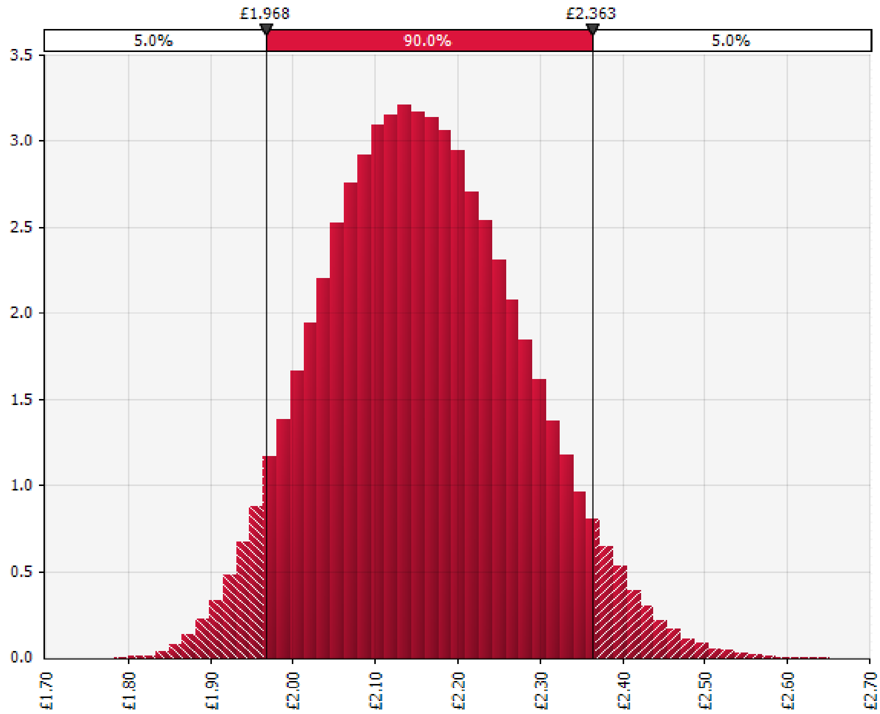
From this analysis it can be seen that using an increased wind turbine size would be beneficial to the project from an economics perspective.

Monte Carlo analysis

As discussed in Section 6.1, as would be expected for this stage of the project, many of the financial modelling inputs have uncertainty associated with them. Therefore Monte Carlo analysis was undertaken in addition to the basecase financial modelling in order to understand the potential range of the key outcomes of the financial model, and the likelihood that these might occur.

The results of the Monte Carlo simulation are summarised in *Figure 6.2* below. *Figure 6.2* demonstrates the potential variation of the implied hydrogen cost as the inputs vary.

Figure 6.2 Hydrogen Price Undiscounted (10MW scale)



7. DEVELOPMENT PLAN

7.1 Short Term Development Plan

The short term development plan for Phase 2 is to develop a 2MW prototype which will be operational and producing around 180 Te of green hydrogen per year by the Summer of 2023. To do this we envisage three phases of work with associated milestones:

Phase 2A – for detailed design work, consenting, regulatory compliance and pre-procurement activities. *Milestone: This work is expected to start around the end of 2019 and be completed by March 2021 (approx. 15 months)*

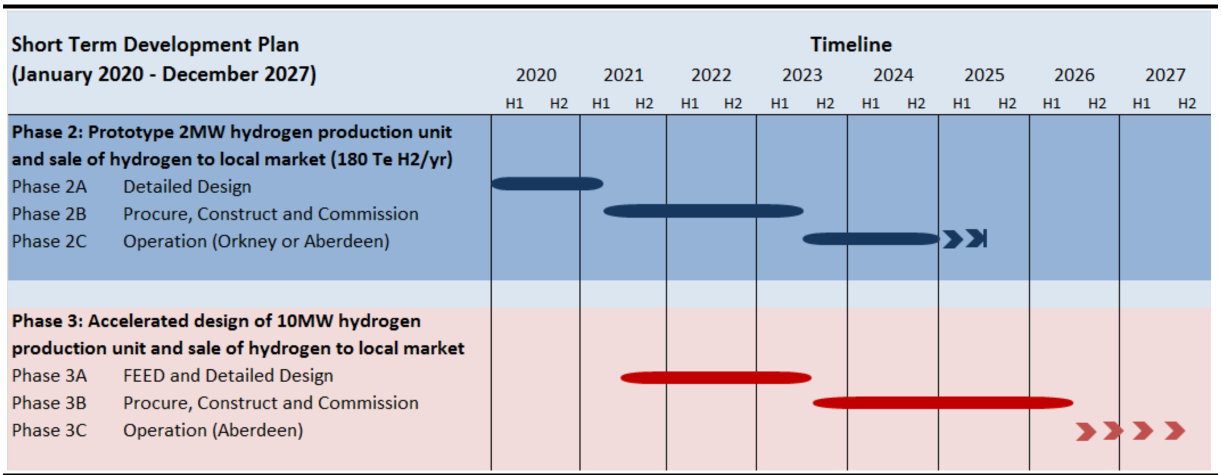
Phase 2B – for procurement, construction and commissioning activities (i.e. building of the 2MW prototype). *Milestone: This work is expected to start middle of 2021 and be completed by middle of 2023 (i.e. approx. 2 years).*

Phase 2C – for operation and testing at location and production of hydrogen for local demand projects and/or blending into local gas network or National Transmission pipeline. *Milestone: Operation is due to start July 2023 and last for 18 months to 2 years (possibly longer depending on performance).*

In addition to the above plan we are exploring options for accelerating the design and development of a full scale 10 MW facility in parallel with the 2MW prototype under a separate 'increased investment' project. This will take advantage of around 14 months of expected 'downtime' caused by delivery of long lead items for the 2MW unit, meaning that we can deliver a 10MW unit with lessons learned from the prototype, by the Summer of 2026. This is a year earlier than our previous plan.

A summary plan for the key activities is presented in *Figure 7.1* below:

Figure 7.1 Short Term Development Plan



7.2 Long Term Development Plan

The projected timescales and development costs for Dolphyn are summarised below based on availability of a bulk scale market for hydrogen in the UK. To reach the levels of production envisaged we have assumed that the hydrogen produced can be blended (up to 15% by 2023) or injected directly (at 100% by 2032) into local distribution or national transmission networks.

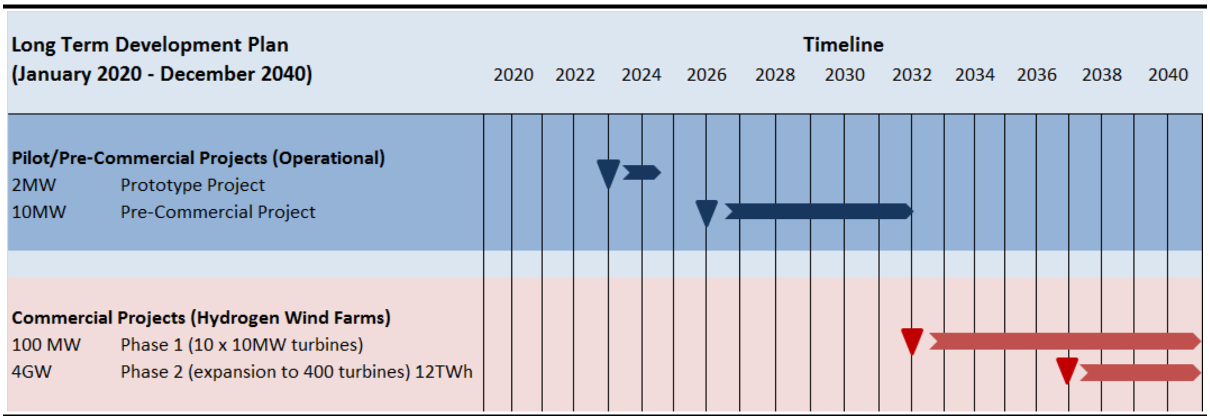
Table 7.1 Dolphyn Long Term Development Plan, Costs and Output (to 2040)

Dolphyn Hydrogen Project: Size of Development	Date	Hydrogen Production Rate (Tonnes/yr)	Hydrogen Production Rate (TWh/y)
2MW - prototype (single operating unit)	2023	180	0.006
10MW – pre-commercial facility (single operating unit)	2026	900	0.03
100 MW- first commercial offshore hydrogen wind farm (10 x 10MW turbines)	2032	9,000	0.30
4GW – first full scale 20 x 20 array hydrogen wind farm (400 x 10MW turbines)	2037	360,000	12.0

From the above plan, we expect hydrogen produced from Dolphyn facilities to reach the target capacity of 10TWh/y hydrogen before 2040. Included in the above analysis are the cost projections provided by manufacturers and expected learning rates taken from similar recent industrial experience (e.g. onshore wind, offshore wind and solar PV) extrapolated up to 2035.

The above plan for Dolphyn showing both pilot/pre-commercial projects as well as commercial projects (ranging from 100 MW to 4GW capacity) is presented graphically in *Figure 7.2*. This shows our projected timeline out to 2040.

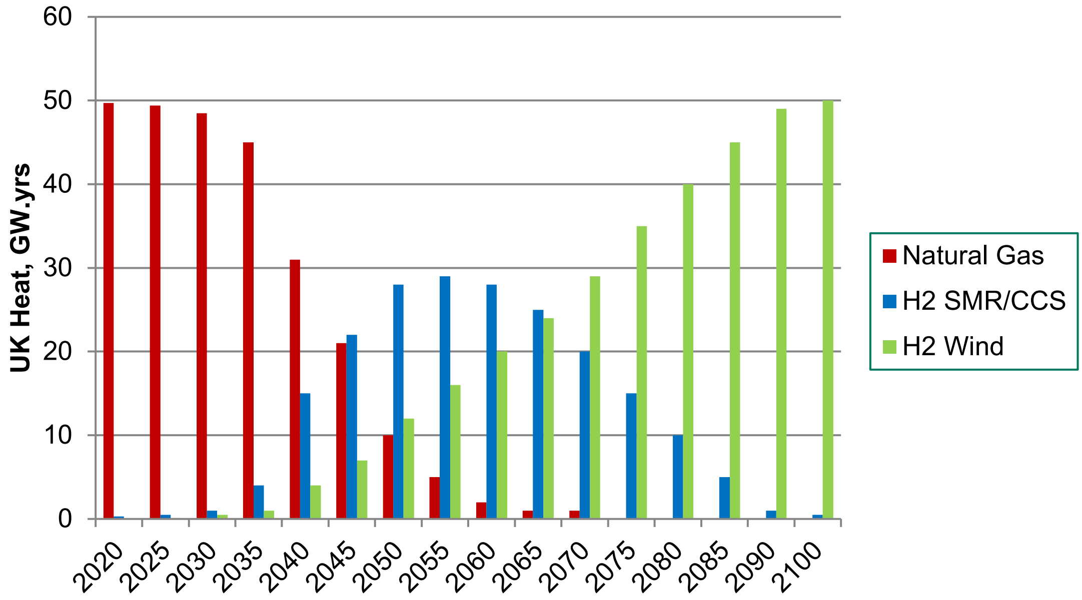
Figure 7.2 Long Term Development Plan (to 2040)



7.2.1 Route to Market

ERM have performed a macroeconomic analysis of what the Dolphyn project could deliver for the UK in terms of energy supply and wider social and economic benefits. This has considered a gradual transition away from fossil fuels over several decades, with SMR/ATR+CCUS being used as a transition technology and green hydrogen complementing and increasingly replacing blue hydrogen as early SMR units reach the end of their operational lifetime. This shows the potential to replace 50% of UK natural gas with hydrogen from offshore wind by 2065 and 100% replacement possible by the end of the century. The study was produced in 2019 for ORE Catapult [1]. The relative energy projections for burning natural gas (red), using natural gas in SMR/ATR with CCS (blue) and use of hydrogen from offshore wind through Dolphyn (green) are shown in *Figure 7.3* below:

Figure 7.3 Hydrogen Supply for 100% UK Gas Network Conversion



ORE Catapult [1]

To produce the above analysis, projections for start-up times of initial SMR and CCS projects (e.g. HyNet, Acorn, etc.) have been taken into account and build-out capacity developed based on supply chain experience in other rapid expansion industry sectors (e.g. UK North Sea Oil and Gas Industry 1960's to 1980's). There have also been assumptions made on the timing of policy decisions and the level of public and private investment needed in infrastructure and the supply chain. Investment in the supply chain will be absolutely essential if the UK is to maximise the benefits of energy transition and meet decarbonisation milestones. The attitude of leading investor institutions toward the opportunity and perceived risks will also be important to enable reasonable financing of debt. In this regard, the Government policy and commitment to supporting both hydrogen from offshore floating wind and CCS will be crucial.

7.3 Accelerating the Development of Bulk Low Carbon Hydrogen

In order to accelerate the development of bulk hydrogen from Dolphyn facilities it will be necessary to develop the first 'bankable' wind farm project, which will show an attractive return for investors. The financing of such a project will invariably include a premium for funding the 'first of a kind' project, which is often seen as high risk. In order to achieve a bankable project, a level of cost reduction, in line with current projections, will need to be achieved to provide favourable comparison against offshore risks from similar floating assets (e.g. oil and gas semi-sub structures). A key aspect will be to employ a standardised sub-structure design as currently proposed. This will enable industry experience to be gained quickly and de-risk future projects. A standardised sub-structure design will also enable high volume, serial fabrication at a number of yards across UK, Europe and elsewhere and enable standardisation of optimised key 'offshore reliable' components such as electrolysers and turbines. An electrolyser manufacturing rate of around 1GW/yr will be required to achieve the build-out rate shown in *Figure 7.3*.

The infrastructure needed for the initial projects, and expansion thereafter, will also require significant investment. Opportunities to re-purpose existing infrastructure (e.g. disused North Sea pipelines such as the Miller to St Fergus pipeline) will be actively explored. To maximise the economic potential for the UK the issues are the same as those for floating wind generally, i.e. Sub-structure Fabrication, Ports and Logistics.

The UK is uniquely placed to be a leader in the development of hydrogen production from offshore wind using Dolphyn facilities. This is due to its outstanding levels of offshore wind resources, leading offshore wind industry and our established oil and gas industry. Our gas distribution network, which will almost be 100% polyethylene by 2030, is another major advantage. The UK is therefore well placed to extract maximum benefit from the technology. The potential climate change, social and economic benefits that could be delivered in the full transition to green hydrogen using Dolphyn, as listed in the ORE report [1], include:

- Production of green hydrogen at scale, comparable to projected prices for natural gas
- New employment of over 8.4 million FTE years cumulatively to 2100
- Investment in UK Ports and traditional areas of manufacturing (particularly UK East Coast)
- Delivery of UK's carbon emissions reduction target by 2050
- No future reliance on gas imports
- Potential to export UK hydrogen technology and services to the rest of the world
- Transition opportunity for the UKNS oil and gas industry
- Delivery of cumulative GVA of £270bn to 2100

To achieve a full transition to green hydrogen is estimated to require a CAPEX of £350bn with £5bn initial public and private sector investment in pre-commercial projects, ports, infrastructure and the supply chain. An investment level of £5-10bn per year would be required for projects through the peak build-out period.

A summary of Dolphyn benefits and key milestones as presented in *Figure 7.4*.

An illustration of how a Dolphyn offshore wind farm network could be developed in the North Sea, for an initial 10 wind farm locations (total 40GW capacity) replacing 50% of UK natural gas needs by 2065, is shown in *Figure 7.5*

Figure 7.4 Summary of Key Benefits and Milestones from the Dolphyn Project

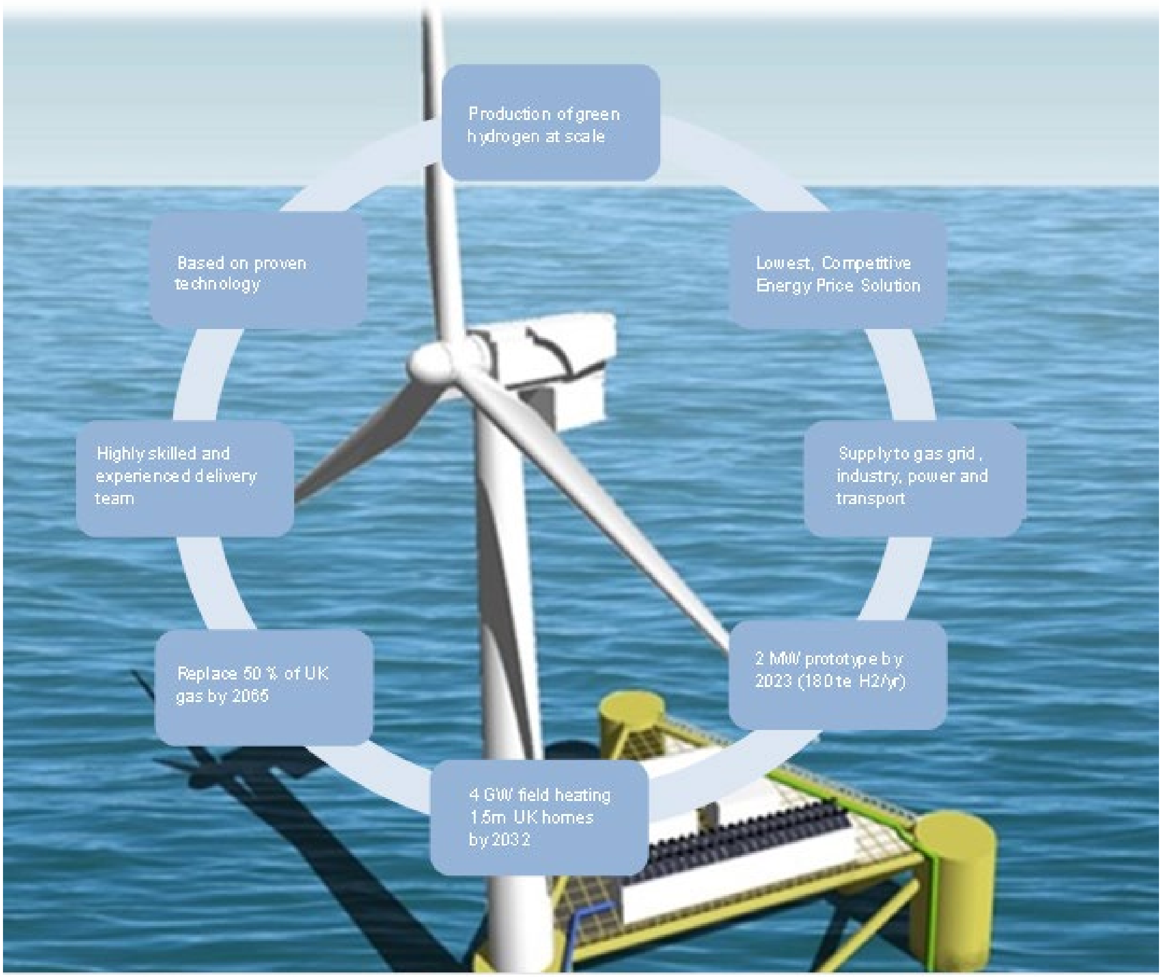
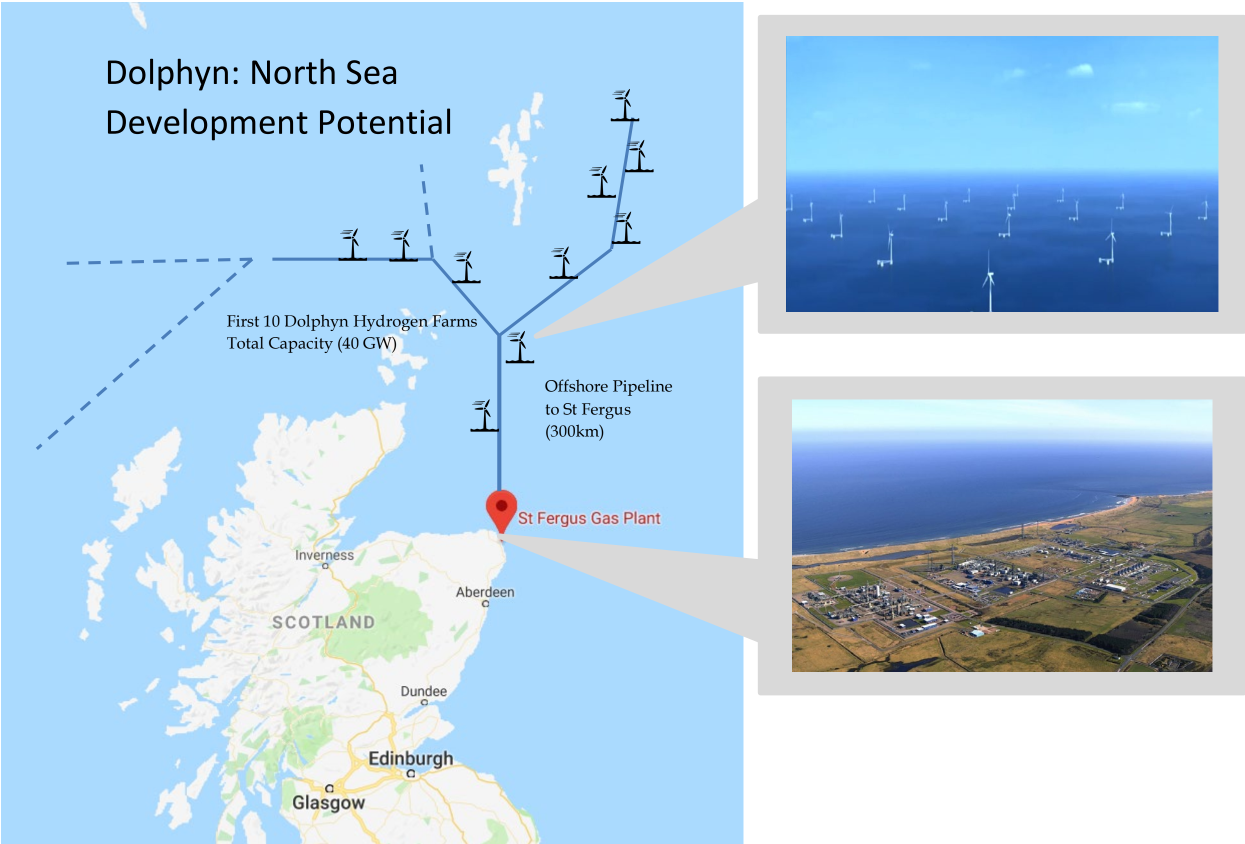


Figure 7.5 Dolphyn North Sea Development Potential (First 10 x 4GW wind farms)



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