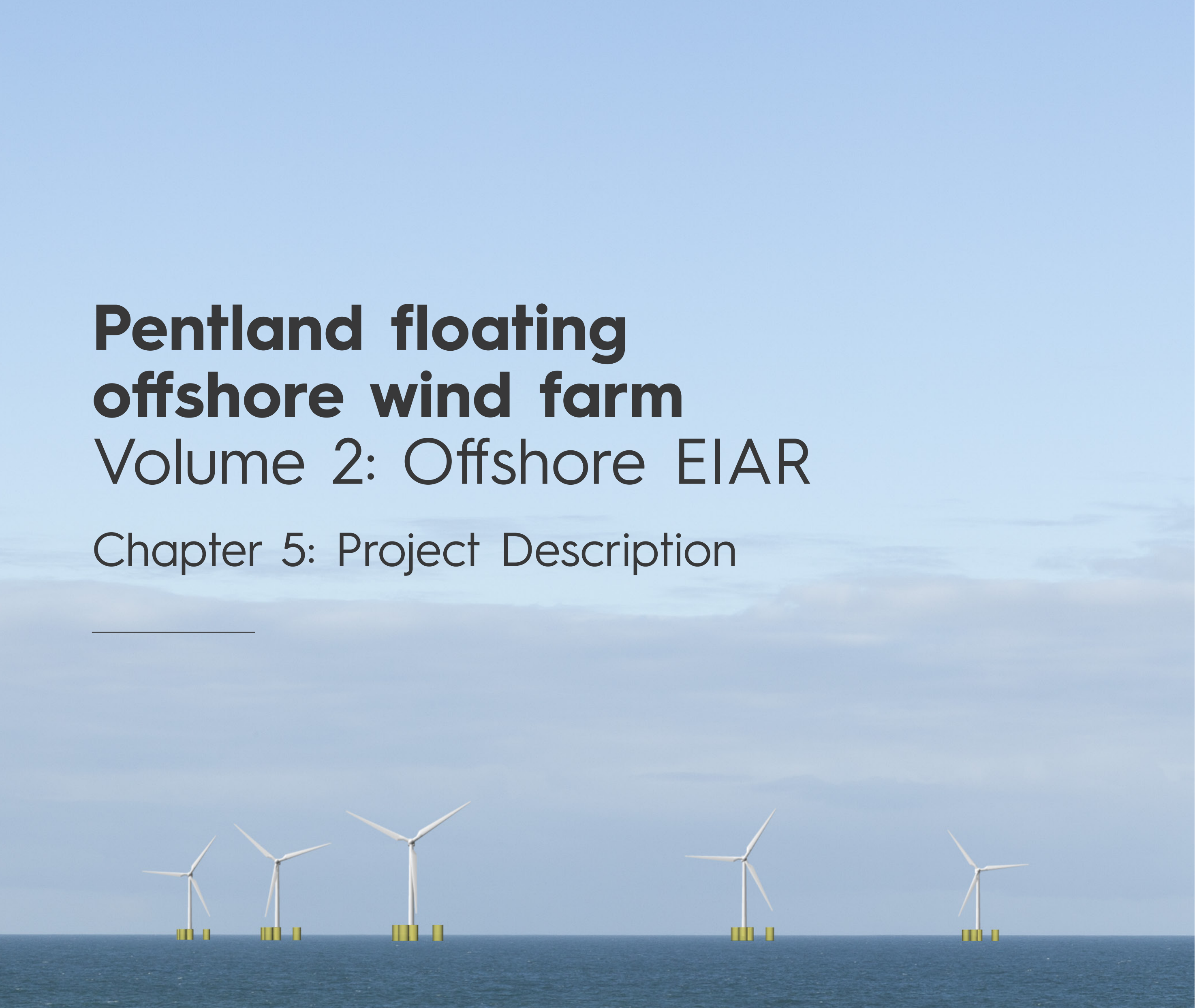
Pentland floating offshore wind farm

Volume 2: Offshore EIAR

Chapter 5: Project Description



PENTLAND FLOATING OFFSHORE WIND FARM

OFFSHORE EIAR (VOLUME 2): MAIN REPORT

CHAPTER 5: PROJECT DESCRIPTION

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GLOSSARY OF PROJECT TERMS

Key Terms	Definition
Dounreay Trì Floating Wind Demonstration Project (the 'Dounreay Trì Project')	The 2017 consented project that was previously owned by Dounreay Trì Limited (in administration) and acquired by Highland Wind Limited (HWL) in 2020. The Dounreay Trì Project consent was for two demonstrator floating Wind Turbine Generators (WTGs) with a marine licence that overlaps with the Offshore Development, as defined. The offshore components of the Dounreay Trì Project consent are no longer being implemented.
Highland Wind Limited	The Developer of the Project (defined below) and the Applicant for the associated consents and licences.
Landfall	The point where the offshore export cable(s) from the PFOWF Array Area, as defined, will be brought ashore.
Offshore Export Cable(s)	The cable(s) that transmits electricity produced by the WTGs to landfall.
Offshore Export Cable Corridor (OECC)	The area within which the offshore export cable(s) will be located.
Offshore Site	The area encompassing the PFOWF Array Area and OECC, as defined.
Onshore Site	The area encompassing the PFOWF Onshore Transmission Infrastructure, as defined.
Pentland Floating Offshore Wind Farm (PFOWF) Array and Offshore Export Cable(s) (the 'Offshore Development')	All offshore components of the Project (WTGs, inter-array and offshore export cable(s), floating substructures, and all other associated offshore infrastructure) required during operation of the Project, for which HWL are seeking consent. The Offshore Development is the focus of this Environmental Impact Assessment Report.
PFOWF Array	All WTGs, inter-array cables, mooring lines, floating sub-structures and supporting subsea infrastructure within the PFOWF Array Area, as defined, excluding the offshore export cable(s).
PFOWF Array Area	The area where the WTGs will be located within the Offshore Site, as defined.
PFOWF Onshore Transmission Infrastructure (the 'Onshore Development')	All onshore components of the Project, including horizontal directional drilling, onshore cables (i.e. those above mean low water springs), transition joint bay, cable joint bays, substation, construction compound, and access (and all other associated infrastructure) across all project phases from development to decommissioning, for which HWL are seeking consent from The Highland Council.

ACRONYMS AND ABBREVIATIONS

AHTS	Anchor Handling Tug Supply
ALARP	As Low As Reasonably Practicable
BEIS	Business, Energy and Industrial Strategy
BPEO	Best Practicable Environmental Option
CAA	Civil Aviation Authority
CaP	Cable Plan
CBRA	Cable Burial Risk Assessment
CEMP	Construction Environmental Management Plan
COLREGs	International Regulations for the Prevention of Collision at Sea
CP	Construction Programme
CTV	Crew Transfer Vessel
DGC	Defence Geographic Centre
DP	Dynamically Positioned
DSLP	Design, Specification, and Layout Plan
EIA	Environmental Impact Assessment
EMF	Electromagnetic Fields
ERCoP	Emergency Response Cooperation Plan
FEED	Front End Engineering and Design
FEPA	Food and Environment Protection Act
FIR	Fisheries Industry Representative
FLO	Fisheries Liaison Officer
FMMS	Fisheries Management and Mitigation Strategy
HDD	Horizontal Directional Drilling
HVAC	High Voltage Alternating Current
HWL	Highland Wind Limited
IMO	International Maritime Organisation
km	kilometre
km^2	square kilometre
LiDAR	Light Detection and Ranging
LMP	Lighting and Marking Plan
m	metres
m^2	square metres
m^3	cubic metres
m/s	metres per second
MARPOL	International Convention for the Prevention of Pollution from Ships

MBES	Multibeam Echo Sounder
MCA	Marine Coastguard Agency
MGN	Marine Guidance Note
MHWS	Mean High Water Springs
MLWS	Mean Low Water Springs
mm	millimetre
MoD	Ministry of Defence
mph	miles per hour
MS-LOT	Marine Scotland-Licensing Operations Team
NLB	Northern Lighthouse Board
NOTAM	Notice to Airmen
NRTE	Naval Reactor Test Establishment
NSP	Navigational Safety Plan
OD	Outer Diameter
OEMP	Operational Environmental Management Plan
Offshore EIAR	Offshore Environmental Impact Assessment Report
OECC	Offshore Export Cable Corridor
OREI	Offshore Renewable Energy Installations
PAC	Pre-application Consultation
PEMP	Project Environmental Monitoring Programme
PFOWF	Pentland Floating Offshore Wind Farm
PS	Piling Strategy
ROV	Remote Operated Vehicle
SAR	Search and Rescue
SCADA	Supervisory Control and Data Acquisition
SF6	Sulphur Hexafluoride
SHE	Scottish Hydro Electric
SOLAS	Safety of Life at Sea
SSE	Scottish and Southern Energy
TDP	Touch Down Point
TLP	Tension Leg Platform
UK	United Kingdom
UXO	Unexploded Ordnance
WTG	Wind Turbine Generator
μT	microtesla

5 PROJECT DESCRIPTION

5.1 Introduction

This chapter of the Offshore Environmental Impact Assessment Report (Offshore EIAR) describes the design details of the Pentland Floating Offshore Wind Farm (PFOWF) Array and offshore export cable(s), hereafter referred to as the 'Offshore Development' and forms the project design basis (the 'Design Envelope') of the impact assessments presented within this Offshore EIAR. For completeness, the PFOWF Onshore Transmission Infrastructure (the 'Onshore Development') is summarised in Section 5.3.2, to provide a full overview of the entire PFOWF Project[i] (both the Offshore Development and Onshore Development). The design of the Offshore Development is described herein, alongside the proposed methods and timing of the construction, operation and maintenance, and decommissioning of the various Offshore Development components.

5.2 Design Envelope Approach

The Offshore Development has adopted a Design Envelope approach to the assessment and application. This is because at this early stage in the development process for the Offshore Development it is not possible to finalise the specifics of the project design, due to:

- Procurement and supply chain considerations associated with emerging technologies;
- The timing of investment decisions; and
- Further site investigations which inform the final project design.

The final Design Envelope of the Offshore Development has been further refined where possible during the Environmental Impact Assessment (EIA) process from that presented in the Scoping Report. Stakeholder comments received in the Scoping Opinion, the Scoping Opinion Addendum, during consultation meetings, and at public events have also been considered. The Design Envelope presented represents the different technology solutions still under consideration and will be further refined as the development of the Offshore Development progresses.

As described in Chapter 6: EIA Methodology, this chapter presents the design parameters which represent the worst case scenarios for each of the receptors that are likely to be affected by this development.

The full Design Envelope is detailed within this chapter and the specific parameters within the Design Envelope that are relevant to the assessment of each receptor are also summarised at the start of each impact assessment chapter within this Offshore EIAR (Chapters 7 to 21). These are presented as the realistic worst case design parameters for each impact identified as requiring assessment for each receptor. This approach ensures that each impact is assessed against the worst case design parameters that are of direct relevance to each specific topic / receptor.

[i] Separate consent from The Highland Council for the Onshore Development components of the Project is required under The Town and Country Planning (Scotland) Act 1997.

5.3 Development Overview

5.3.1 Development Boundary

The Offshore Development is located wholly within the Offshore Site within which the applications for consent are being sought. This includes:

- The PFOWF Array Area: The area where the Wind Turbine Generators (WTGs) and associated infrastructure will be located. This is an area of 10 square kilometres (km^2) located approximately 7.5 kilometres (km) off the coast of Dounreay, Caithness, at its closest point to shore; and
- The Offshore Export Cable Corridor (OECC): The area where the offshore export cable(s) will be located. The corridor runs from the boundary of the PFOWF Array Area up to Mean High Water Springs (MHWS) mark.

The Offshore Site has been refined from the footprint presented during Scoping following consultation responses received during the Pre-application Consultation (PAC) event held in May 2022 (as detailed in Chapter 4: Stakeholder Engagement and the PAC Report accompanying this application).

Refinement to the PFOWF Array Area was undertaken to increase the setback of the PFOWF Array Area from the Dounreay coast and to reduce the size of the PFOWF Array Area, thereby reducing the horizontal spread of the WTGs and minimising potential visual impacts on land-based receptors. This also has the added benefit of reducing the overall footprint on other receptors including other sea users, commercial fisheries interests and displacement to ornithology receptors.

In addition, from the maximum worst case scenario presented in the Scoping Report (HWL, 2020) and Scoping Report Addendum (HWL, 2021), the maximum number of WTGs to be deployed has been reduced from 10, down to seven, further reducing potential visual impacts and impacts on other receptors including commercial fisheries and ornithology.

The Offshore Development will also comprise up to two subsea offshore export cables which will export the renewable electricity ashore within the OECC (Figure 5.1).

The Offshore Development will connect to the Onshore Substation, which will in turn connect to the grid at the existing 132-Kv Scottish and Southern Energy (SSE) Dounreay substation. The coordinates of the Offshore Development are provided in Table 5.1 and Table 5.2.

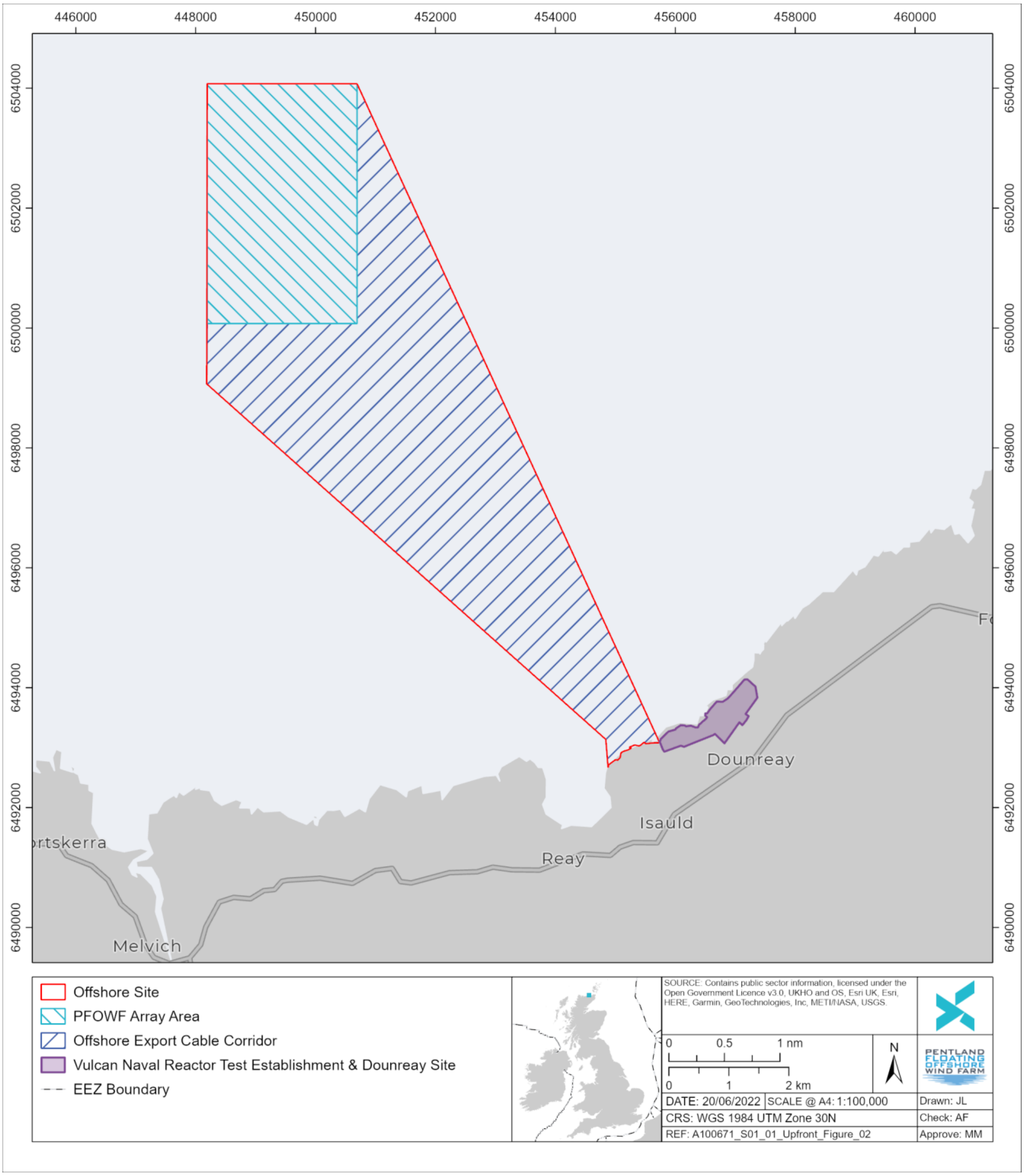


Figure 5.1 Offshore Development boundary

Table 5.1 PFOWF Array Area coordinates (degrees and decimal minutes)

Corner	WGS84 Latitude	WGS84 Longitude
NE	58° 40.445' N	3° 51.014' W
NW	58° 40.427' N	3° 53.600' W
SE	58° 38.290' N	3° 50.962' W
SW	58° 38.272' N	3° 53.545' W

Table 5.2 Offshore Export Cable Corridor coordinates (degrees and decimal minutes)

Vertex ID	WGS84 Latitude	WGS84 Longitude
1	58° 34.605' N	3° 45.709' W
2	58° 34.603' N	3° 45.748' W
3	58° 34.571' N	3° 45.798' W
4	58° 34.570' N	3° 45.873' W
5	58° 34.562' N	3° 45.928' W
6	58° 34.525' N	3° 46.007' W
7	58° 34.537' N	3° 46.101' W
8	58° 34.513' N	3° 46.167' W
9	58° 34.516' N	3° 46.119' W
10	58° 34.490' N	3° 46.188' W
11	58° 34.484' N	3° 46.286' W
12	58° 34.453' N	3° 46.339' W
13	58° 34.420' N	3° 46.370' W
14	58° 34.399' N	3° 46.451' W
15	58° 34.341' N	3° 46.550' W
16	58° 34.533' N	3° 46.583' W
17	58° 34.547' N	3° 46.586' W
18	58° 34.579' N	3° 46.591' W
19	58° 37.730' N	3° 53.540' W
20	58° 40.427' N	3° 53.600' W
21	58° 40.445' N	3° 51.014' W

5.3.2 Outline Description of Development

The key components of the Offshore Development described in further detail within this chapter, are outlined below:

> Up to seven floating offshore Wind Turbine Generators (WTGs);
> Up to seven associated floating substructures;
> Up to nine mooring lines for each floating substructure (63 in total);
> Up to nine anchors or piles for each floating substructure (63 in total);
> Up to seven inter-array cables (dynamic and static);
> Up to two offshore export cables (continuation of inter-array cables to bring power ashore), with landfall achieved via Horizontal Directional Drilling (HDD); and
> Associated scour protection and cable protection (if required).

The key components of the Onshore Development, which is located within the Onshore Site (the area encompassing the Onshore Development site boundary where the substation and associated onshore infrastructure will be located, down to the mean low water springs [MLWS] mark), include:

> Horizontal directional drilling (HDD) Bay
> Onshore export cables;
> Joint bays;
> Onshore substation compound;
> Grid connection works and cables to the grid connection point;
> Temporary construction compounds; and
> Access routes.

Figure 5.2 provides an overview of the key Project components.

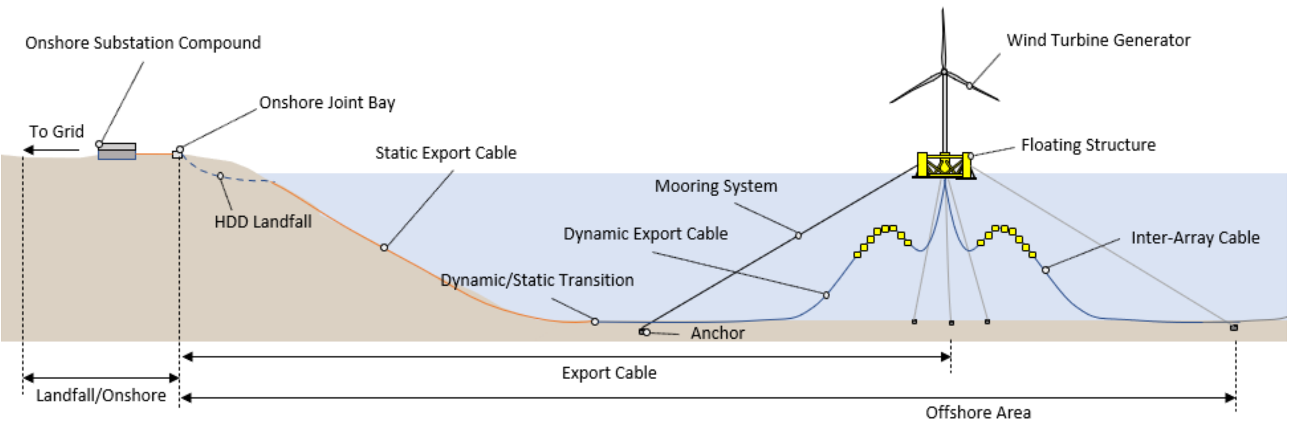


Figure 5.2 Key Project components

The offshore construction activities are anticipated to commence in 2024 with the commencement of HDD works at the landfall (further detail of these works is provided in Section 5.7.7). Construction of the wind farm and installation of the offshore export cable(s) is then anticipated to take place in two stages with anchor installation taking place in 2025 (Stage 1) and the offshore export cable(s) taking place in either 2025 (Stage 1) or 2026 (Stage 2), but not both. The remaining offshore components are anticipated to be installed in 2026 (Stage 2). A single WTG and associated floating foundation are likely to be installed during Stage 1, with the remaining WTGs installed in Stage 2. Stages 1 and 2 are expected to take place over a total period of approximately 18 months. Further information on the construction programme is provided in Section 5.8. It is anticipated that the Offshore Development will be fully commissioned and operational by Q4 2026.

It should be noted that these are anticipated construction years only and it is possible that the construction programme may change. However, overall anticipated timescales for project works will remain the same. The final construction programme for the Offshore Development will be confirmed in the Construction Programme consent plan which will be required as a condition of the consent.

Fabrication and assembly of all the components are expected to commence in Q4 2024 and run through to Q1/Q2 2026. Offshore components will be fabricated onshore and, in the case of the WTGs, these are likely to be constructed offsite and towed directly to the PFOWF Array Area. A number of construction ports for the installation of the Offshore Development are still being considered and the construction port will be confirmed prior to construction.

Timescales are subject to the Project securing all relevant consents and a route to market through the Contracts for Difference process, as well as the finalisation of procurement and supply chain contracts. It is expected that the design life of the WTGs and hence the operational life of the Offshore Development will be up to 30 years.

5.3.3 Embedded Mitigation and Management Plans

The design of the Offshore Development will include embedded mitigation measures and various management plans that will further mitigate potential impacts. These management plans will form conditions to the consent, should it be granted. This includes all embedded mitigation and identifies additional mitigation which will be in place during the relevant phases of construction, operation and maintenance, and decommissioning.

Embedded mitigation is that which has been recognised as having benefits in reducing impact significance and is contained within the design of the Offshore Development. These mitigations form part of the application for development consent and will be described in detail during the condition discharge stage, should consent be granted. Additional mitigations for the Offshore Development are those measures which may be required in addition to design embedded mitigation and are detailed within each technical chapter. A summary of the embedded mitigations and Management Plans for the Offshore Development is presented in Table 5.3, and a full list of all the identified mitigations for the Offshore Development is provided in Chapter 21: Summary of Offshore Impacts.

Table 5.3 Embedded mitigation measures and management plans for the Offshore Development

Embedded Mitigation and Management Plans	Description
Embedded Mitigation	
PFOWF Array Area and number of WTGs	Refinement to the PFOWF Array Area was undertaken to increase the setback of the PFOWF Array Area from the Dounreay coast and reduce the size of the PFOWF Array Area thereby reducing the horizontal spread of the WTGs and minimising potential visual impacts on land-based receptors. In addition, the maximum number of WTGs to be deployed has been reduced from ten down to seven, further reducing potential visual impacts and impacts on other receptors including ornithology.

Embedded Mitigation and Management Plans	Description
Minimum Air Gap	Minimum air gap from mean sea level will be 35 m, greater than the minimum 22 m required to comply with SAR requirements. This is to reduce potential risks to ornithological receptors.
Minimum Spacing between WTGs	The minimum spacing between each WTG (from the centre of each WTG structure) will be 800 m.
Micrositing of WTGs and associated offshore infrastructure including cable routes	The final Offshore Development layout will be presented within the CaP and Design Specification and Layout Plan and conditions of the Section 36 Consent and/or Marine Licence. The final placement of infrastructure will be informed through micrositing based on available site survey data to ensure avoidance of sensitive habitats, archaeological and other structures where possible. Where this is not possible, the route will take the shortest distance possible through the sensitive areas to reduce environmental effects.
Use of HDD as the landfall cable installation option	HDD negates the need to pin the export cable to the disused water intake which raised concerns about potential effects on coastal morphology and impacts on Sandside Bay SSSI.
Reducing Localised Habitat Loss	Localised habitat loss during the installation phase is an unavoidable consequence of the Offshore Development. Best practice will be followed to ensure that potential habitat loss is minimised throughout the proposed works (e.g. micrositing and minimising the benthic footprint of the Offshore Development). The amount of rock armour, grout bags, and concrete mattresses used to protect the offshore export cables will be kept to a minimum where possible.
Removal of Marine Growth	The substructures will be designed to accommodate marine growth; however, to manage weight / drag-induced fatigue, growth levels will be inspected regularly, and subsequent removal of this growth will be undertaken using water jetting tools if substantial accumulation is in evidence.
Removal of debris from floating lines and cables	Mooring lines and floating inter-array cables will be inspected with a risk-based frequency during the operational life-cycle of the Offshore Development, starting at a higher frequency and likely declining after a number of years, based on evidence gathered during inspections. Any inspected or detected debris on the floating lines and cables will be recovered based on a risk assessment which considers impact on environment, risk to asset integrity and cost of intervention.
Application of scour protection	The Project Design Envelope includes the installation of scour protection around the anchor installations within the PFOWF Array Area. This will therefore negate the introduction of scour during the Offshore Development operation stage. The potential scale and requirement for scour protection will be informed by scour studies and the selected anchor solution.
Charting Requirements	Prior to construction, the positions and final height of the WTGs will be provided to the United Kingdom Hydrographic Office, MoD, and Defence Geographic Centre (DGC) for aviation and nautical charting purposes. All structures of more than 91.4 m in height will be charted on aeronautical charts and reported to the DGC, which maintains the United Kingdom's database of tall structures (Digital Vertical Obstruction File) at least ten weeks prior to construction. The Offshore Development infrastructure, including cables mooring lines, anchoring points, as well as WTGs and floating foundations, will be plotted and provided to other sea users to be uploaded on their plotters.

Embedded Mitigation and Management Plans	Description
Promulgation of information as per consent requirements and standard industry practice.	As per required consent conditions, the details of the Offshore Development will be promulgated in advance of, and during, construction via channels such as Notices to Mariners and Kingfisher bulletins to ensure shipping and navigation users are informed about ongoing and upcoming works.
MoD and Dounreay Site Notification	Due to the proximity of the Vulcan Naval Reactor Test Establishment (NRTE) and Dounreay Site, prior to construction, Highland Wind Limited (HWL) will notify the MoD and Dounreay Site of any offshore works being undertaken and the duration of activities for the Offshore Development for compliance with security measures of these nuclear sites, including any activities within the Dounreay Food and Environment Protection Act (FEPA) zone offshore of the Dounreay Site.
Fisheries Liaison Officer (FLO) and Fisheries Industry Representative (FIR)	An FLO and FIR will be appointed to establish effective communications surrounding the Offshore Development with local fishermen and other sea users. The FLO will distribute information on the safe operations of fishing activities at the site and will be a contact for fishermen and other sea users during the lifetime of the Offshore Development. The FIR will liaise with the wider fishing industry. The specific roles and responsibilities will be defined within the FMMS.
Environmental Clerk of Works	An independent Environmental Clerk of Works will be appointed to audit site activities and will advise on the implementation of mitigation.
Notice to Mariners, Kingfisher notifications and other navigational warnings on the location, duration and nature of works.	HWL will issue Notice to Marines, Kingfisher notifications, and other navigational warnings, as required and in a timely and efficient manner. This ensures navigational safety and minimises the risk of equipment snagging through the appropriate propagation of notices to other sea users.
Target depth of lowering	Static cables will be trenched and buried to a minimum target depth of 0.6 m. Where this can not be achieved, remedial cable protection will be applied. The cable burial target depth will be informed by a CBRA and implemented through the CaP produced post-consent.
Nacelle, Tower, and Rotor Design	The nacelle, tower, and rotor are designed and constructed to contain leaks thereby reducing the risk of spillage into the marine environment.
Marine Guidance Note (MGN) 654 compliance	The Offshore Development will comply with MGN 654 and its annexes as per its consent conditions to ensure that impacts on navigational safety and emergency response are considered, assessed, and mitigated where necessary. This includes post-consent completion of the Search and Rescue Checklist which includes the completion of an ERCoP.
Any temporary obstacles associated with wind farms which are of more than 91.4 m in height are to be alerted to aircrews through the Notice to Airmen (NOTAM) system.	Consultation with the CAA will be required to ensure that temporary obstacles of more than 91.4 m are identified to aircrews by NOTAM. Notification of temporary obstacles will be a condition of the Section 36 Consent and Marine Licence. Measures will be adopted to ensure that the potential risk of aircraft collision with construction, operation and maintenance, and decommissioning infrastructure is minimised.
Post-consent application for safety zones	Five-hundred-metre safety zones will be applied for during construction, major maintenance, and decommissioning works. These will be centred on the Offshore Renewable Energy Installations (OREI) being worked on at the time. In addition, a 500-m advisory safety zone will also be requested around project vessels (e.g. during cable-laying). Operational safety zones are under consideration for the Offshore Development in terms of their status (advisory or statutory) and extent. If statutory operational safety zones are planned, further consultation will be

Embedded Mitigation and Management Plans	Description
	held with stakeholders before making an application, which will be supported by risk-based justification.
Adherence with the International Convention for the Control and Management of Ships' Ballast Water and Sediments, 2004 (BWM Convention)	Ballast water discharges from vessels will be managed under the BWM Convention which aims to prevent the spread of harmful aquatic organisms from one region to another, by establishing standards and procedures for the management and control of ships' ballast water and sediments. Measures will be adopted to ensure that the risk of Invasive Non-Native Species introduction during construction, operation and maintenance, and decommissioning is minimised.
Procedures for dropped objects and claim processes for loss / damage to fishing gear / vessels.	Protocols and procedures for dropped objects will be developed and outlined within the FMMS to minimise the risk of equipment snagging from large, dropped objects associated with the Offshore Development.
International Regulations for the Prevention of Collision at Sea (COLREGs) and the International Regulations for the Safety of Life at Sea (SOLAS).	All vessels will comply with the provisions of the COLREGs and the SOLAS, including the display of appropriate lights and shapes such as when vessels are restricted in their ability to manoeuvre.
Adherence to the International Convention for the Prevention of Pollution from Ships (MARPOL)	All vessels will operate in adherence with MARPOL requirements. Accordance with this will help to ensure that the potential for release of pollutants is minimised during operations.
Buoyed construction area	As agreed in consultation with NLB, construction buoyage will be deployed to mark the PFOWF Array Area. Construction buoyage will be secured through the LMP.
The use of guard vessels and Offshore Fisheries Liaison Officers, where required.	The appointment of guard vessels and Offshore Fisheries Liaison Officers during construction, major maintenance works, and decommissioning works, where required, ensures effective communication with the fishing community during the Offshore Development activities and reduces the potential for interactions with fishing activities. Where possible, guard vessels will be sourced locally and, as a minimum, will be Scottish vessels.
Crossing and Proximity Agreements	Crossing and proximity agreements will be established with Scottish Hydro Electric (SHE) Transmission, if required, in consultation with SHE Transmission.
Unexploded Ordnance (UXO)	UXO will be identified through pre-construction surveys. UXO will be avoided where possible. However, if further mitigation such as clearance or detonation is required, this would be subject to separate assessment and applications.
Management Plans	
Construction Environmental Management Plan (CEMP)	A CEMP will be developed for the Offshore Development, this will set out procedures to ensure all activities with the potential to affect the environment are appropriately managed and will include: a description of works and construction processes, roles and responsibilities, description of vessel routes and safety procedures, pollution control and spillage response plans, incident reporting, chemical usage requirements, waste management plans, plant service procedures, communication and reporting structures and timeline of work. It will detail the final design selected and take into account Marine Licence Conditions.

Embedded Mitigation and Management Plans	Description
Emergency Response Cooperation Plan (ERCoP)	The ERCoP will be in place for the Offshore Development. The ERCoP will refer to the marking and lighting of the WTGs and will consider helicopters undertaking Search and Rescue (SAR) operations when rendering assistance to vessels and persons in the vicinity of the PFOWF Array Area.
Marine Pollution Contingency Plan	Consent conditions will require a Marine Pollution Contingency Plan to outline procedures in the event of an accidental pollution event arising from activities associated with the Offshore Development.
Construction Method Statement (CMS)	A Construction Method Statement will be developed in accordance with the CEMP and detail how project activities and plans identified within the CEMP will be carried out, whilst also highlighting any possible dangers / risks associated with specific Offshore Development activities.
Project Environmental Monitoring Programme (PEMP)	Through the EIA process, conclusions have been drawn on the potential environmental impact of developing the Offshore Development. Where required, a monitoring plan will be put in place to provide further evidence to support these conclusions and provide information for future offshore wind farm developments. Pre-, during, and post-construction and operation surveys on aspects such as commercial fisheries, shipping, benthic ecology, fisheries, marine mammals, and birds will be considered as part of the Project Environmental Monitoring Plan.
Design Statement (DS)	A Design Statement will be submitted for the Offshore Development detailing the final design of the Offshore Development infrastructure. This will include visualisations of how the final design for the array will look from selected viewpoints.
Development, Specification, and Layout Plan (DLSP)	A DSLP will allow stakeholders to see the specifics of the Offshore Development (e.g. WTG positions within the array and mooring arrangement position).
Cable Plan (CaP) / Cable Burial Risk Assessment (CBRA)	A CaP will be provided for the Offshore Development which will detail the location / route and cable laying techniques of the inter-array and offshore export cables and detail the methods for cable surveys during the operational life of the cables for the Offshore Development. This will be supported by survey results from the geotechnical, geophysical, and benthic surveys. The Cable Plan will also detail the electromagnetic fields of the cables deployed. A CBRA will also be undertaken and included within the CaP which will detail cable specifications, cable installation, cable protection, target burial depths / depth of lowering and any hazards the cable will present during the lifetime of the cable.
Piling Strategy (PS)	A Piling Strategy will be prepared for the Offshore Development if impact piling is selected as the optimal installation mechanism for the WTG foundations. The strategy will provide full details of the piling activities and parameters, including expected noise levels, duration of activities and any required mitigations associated with this installation technique (e.g. Marine Mammal Observer or Passive Acoustic Monitoring).
Marine Mammal Mitigation Plan (MMMP)	A MMMP will be developed and implemented throughout all phases of the Offshore Development to ensure the risk of injury to marine mammals is negligible and all possible disturbance effects are reduced. Best Available Technology will be employed along with due consideration of the local environment (e.g. protected sites or other important habitats) in line

Embedded Mitigation and Management Plans	Description
	with the JNCC (2010) guidance: “The protection of marine European Protected Species from injury and disturbance’ and the Marine Scotland (2020) guidance: The protection of Marine European Protected Species from injury and disturbance, Guidance for Scottish Inshore Waters.
Vessel Management Plan (VMP)	A Vessel Management Plan will be prepared for the Offshore Development which will detail the number, type and specification of vessels utilised during construction and operation. This will also detail the ports and transit corridors proposed.
Navigational Safety Plan (NSP)	A Navigational Safety Plan will be developed for the Offshore Development which will detail all navigational safety measures, construction exclusion zones if required, notices to mariners and radio navigation warnings, anchoring areas, lighting and marking requirements and emergency response procedures during all phases of the project.
Lighting and Marking Plan (LMP)	A Lighting and Marking Plan will be developed for the Offshore Development. This will provide that the Offshore Development be lit and marked in accordance with the current Civil Aviation Authority (CAA) and Ministry of Defence (MoD) aviation lighting policy and guidance. The LMP will also detail the navigational lighting requirements detailed in IALA R139 and G1162.
Fisheries Management and Mitigation Strategy (FMMS)	An FMMS will be prepared for the Offshore Development. This FMMS will detail the methods for monitoring and collecting data on the effects from the Offshore Development on local fishermen and other sea users in accordance with the findings of the EIA. The strategy will also detail the mitigations proposed for commercial fisheries identified.
Operational Environmental Management Plan (OEMP)	An OEMP will be developed to guide ongoing operations and maintenance activities during the lifetime of the Offshore Development. The OEMP will also set out the procedures for managing and delivering the specific environmental commitments as per each technical chapter for each receptor over the operational period.
Construction Programme (CP)	A Construction Programme will be developed detailing the construction activities and schedule for the Offshore Development.
Decommissioning Programme (DP)	A Decommissioning Programme will be provided pre-construction to address the principal decommissioning measures for the Offshore Development, this will be written in accordance with applicable guidance and detail the management, environmental management, and schedule for decommissioning.
Protocols for managing radioactivity risk	A Radioactive Risk Assessment has been completed to inform all stages of the Offshore Development. Associated with the risk assessment are a number of recommendations including protocols and procedures for managing and mitigating the risk of coming in contact with and spreading radioactive particles. These protocols and procedures are to be adopted and implemented as part of Offshore Development operations and will form part of the Offshore Development environmental management plans.

5.4 PFOWF Array Area Infrastructure

The following sections describe the different components associated with the PFOWF Array Area infrastructure.

5.4.1 Wind Turbine Generators

5.4.1.1 WTG design parameters

The WTG Design Envelope must provide enough flexibility to accommodate innovations in currently available WTG technologies. As such the Offshore Development is considering a range of WTG options and associated dimensions against which the environmental impacts of the Offshore Development can be assessed, however, all WTGs follow conventional offshore design architecture with three blades and a horizontal rotor axis.

Due to the fast pace of WTG technology development, it is not considered appropriate to constrain the Design Envelope based on the capacity of individual WTGs. The receptor-specific impact assessments undertaken as part of this EIA are not linked to, or affected by, WTG capacity. Instead, the number and physical dimensions of the WTGs are the relevant aspects and hence these parameters are described below and used within the impact assessments.

Figure 5.3 shows an illustrative WTG, with definitions of the numeric parameters referenced within Table 5.4. Whilst the exact dimensions of the WTG cannot be finalised at this stage due to procurement and supply chain considerations, associated with the use of emerging technology (both on floating foundations and WTG technologies),

Table 5.4 details the upper limits for the individual WTG parameters; the final parameters and number of WTGs being deployed will fall within these ranges.

In defining worst case scenarios for WTG parameters, it should be noted that the Offshore Development will install a maximum of seven WTGs, up to a maximum rotor diameter of 260 metres (m) and 300 m maximum tip height. Should Highland Wind Limited (HWL) proceed with the largest WTG (e.g. 300 m height and a rotor diameter of 260 m), this would result in fewer than seven WTGs being required to meet the anticipated generating capacity of the Offshore Development. Within the assessments undertaken, a worst case scenario has been defined for each receptor based on the combination of WTG number and dimensions that would give rise to the greatest level of impact. These receptor worst case scenarios are defined within each of the technical assessment chapters within this document.

Table 5.4 Worst case design parameters for WTGs

Design Parameter	Scenario range
Maximum number of WTGs	Up to 7
Minimum blade clearance from sea-level	35 m
Maximum hub height (HAT)	Up to 190 m
Maximum rotor diameter	Up to 260 m
Maximum tip height (HAT)	Up to 300 m
Total rotor swept area (maximum 7 WTGs)	371,650 square metres (m^2)
Minimum spacing between WTGs	800 m

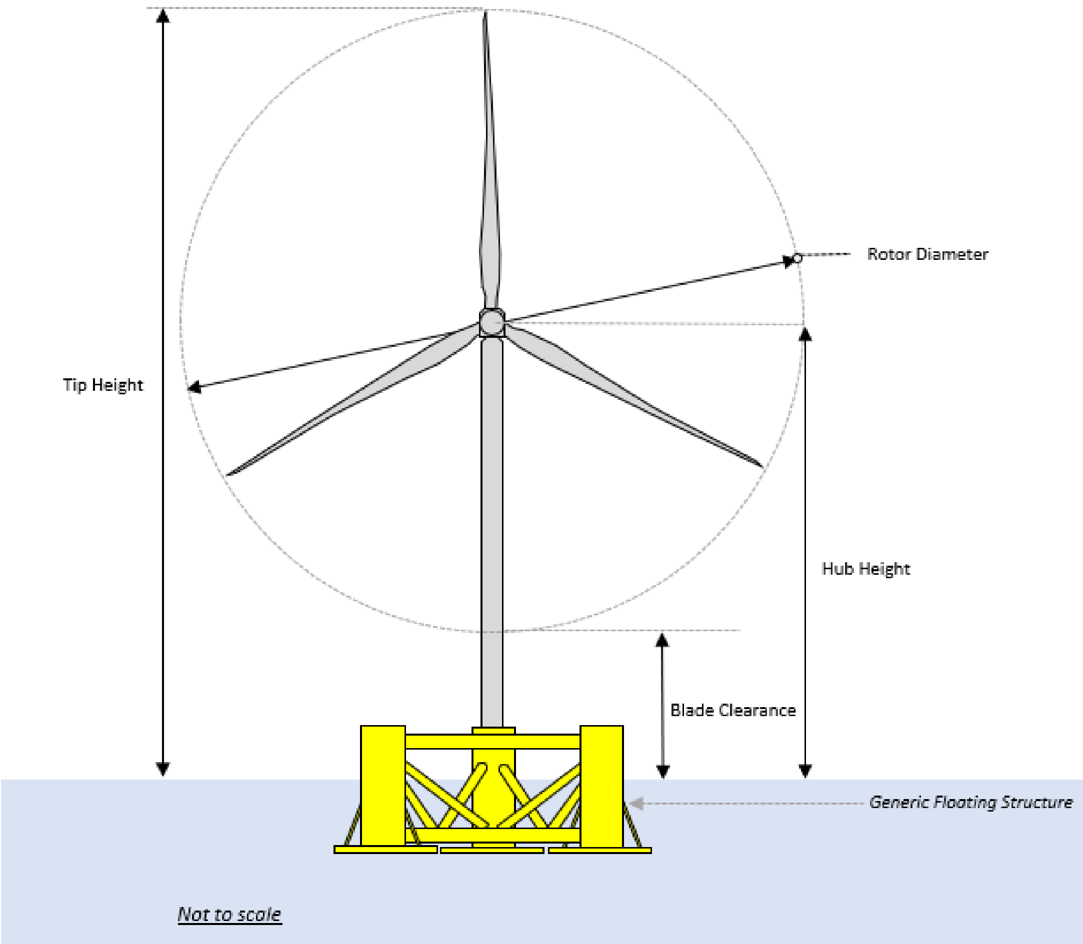


Figure 5.3 Illustration of the design parameter definition for a WTG

5.4.1.2 WTG layout

The WTG layout will be determined once the design optimisation process has been completed. This is an iterative process balancing a number of key development sensitivities including WTG model choice and wind direction, geophysical characteristics, metocean conditions, benthic habitats, floating substructure and anchor design, and navigational safety considerations.

5.4.1.3 WTG control systems

Each WTG operates automatically. Each WTG can yaw (where the nacelle rotates to face the rotor blades into the wind). The rotor blades can also pitch (where the blades can rotate into or out of the wind depending on the wind speed). Each WTG is self-starting when the wind speed reaches an average of about 3 metres per second (m/s) to 5 m/s (about 10 miles per hour [mph]). The output increases with the wind speed until the wind speed reaches typically 10 m/s to 13 m/s (about 25 mph). At this point, the power is regulated at rated (maximum) power. When the maximum operational wind speed is reached, typically 25 m/s to 30 m/s (about 60 mph), the WTG will cut-out, either fully or gradually, to limit loading. If the high wind speed cut-out is gradual, the WTG will continue to generate some power through to higher wind speeds; the maximum is dependent on the WTG design. A SCADA (Supervisory Control and Data Acquisition) computer system monitors and controls the output from each WTG. An integrated alarm system will be triggered automatically in the event of a fault.

5.4.1.4 Oils and fluids

Every WTG contains components that require lubricating oils, hydraulic oils, and coolants for operation. Examples of these are:

> Grease;
> Synthetic oil / hydraulic oil;
> Nitrogen;
> Transformer silicon / oil;
> Sulphur Hexafluoride (SF_6); and
> Water / glycerol.

To minimise the impact from an unlikely leak of any of these fluids, the nacelle, tower, and rotor are designed and constructed to contain leaks thereby reducing the risk of spillage into the marine environment.

5.4.2 Floating Substructures

5.4.2.1 Substructure concepts

The WTGs will be supported by a floating substructure, the specific technology and make-up of which have not yet been selected. There are over 40 floating WTG structure concepts currently at varying stages of development in the industry. These have been summarised into two characteristic design options for consideration within the Design Envelope of the Offshore Development. These consist of semi-submersible and Tension Leg Platform (TLP) as shown in Figure 5.4.

An overview of the options for WTG floating substructures is presented in Table 5.5. Each floating technology has varying dimensions as a result of the different approaches to meeting the unique engineering challenges associated with floating WTGs, WTG sizes, and project-specific requirements. Typical dimensions for each of the floating technologies can be estimated, based on existing designs from both concept and demonstration scale examples. Indicative dimensions for each floating technology are presented in Table 5.5. Due to the immature nature of the floating offshore wind industry, the dimensions of any final design may vary significantly from current estimates, based on the emergence of new technologies and approaches in all aspects of the design, manufacturing, and installation processes. As such, Table 5.5 outlines the maximum dimensions for each of the floating technologies which will not be exceeded, based on the larger WTG scenario presented in Section 5.4.1.

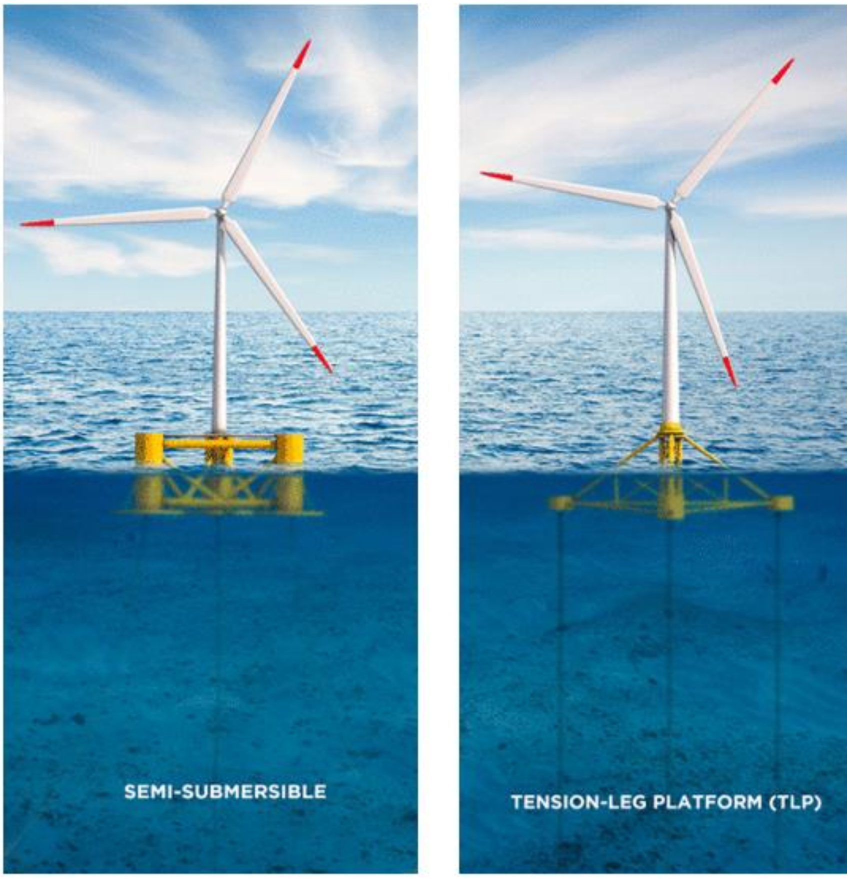
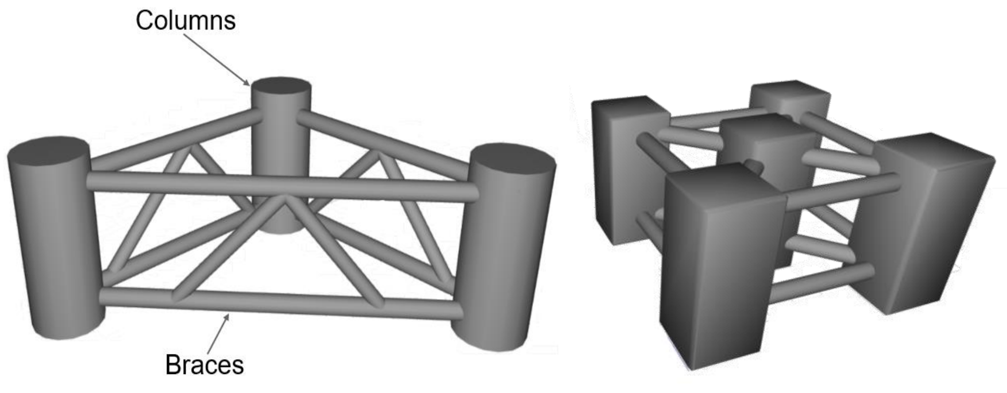


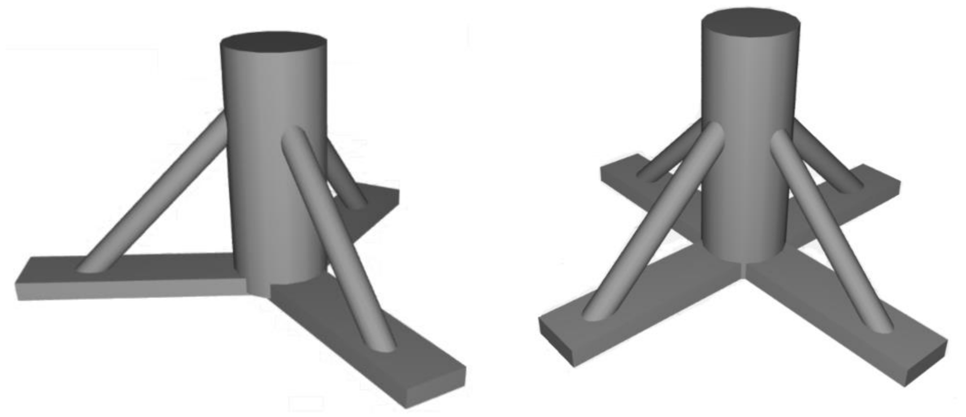
Figure 5.4 Illustration of characteristic floating substructure designs (Image from WindEurope)

5.4.2.2 Substructure design parameters

Although the dimensions of the various floating substructure designs differ significantly depending on the type of structure, the overall platform design parameters and sea surface footprint being considered within the Design Envelope for the Offshore Development will not exceed those of the square semi-submersible or TLP, as presented in Table 5.5.

Table 5.5 Floating substructure features worst case design parameters

<table>
<tr><th>Floating substructure</th><th>Description</th><th>Indicative Maximum dimensions per substructure</th></tr>
<tr><td>Semi-submersible</td><td>A buoyancy stabilised platform which floats semi-submerged on the surface of the ocean whilst anchored to the seabed. The structure gains its stability through the buoyancy force associated with its large footprint and geometry which ensures the wind loadings on the structure and WTG are countered / dampened by the equivalent buoyancy force on the opposite side of the structure. These can be either triangular or square substructures, as shown below.


(Images indicative, geometry may change)</td><td><table>
<tr><th colspan="2">Semi-submersible</th></tr>
<tr><td>Max Length (L) (m)</td><td>125</td></tr>
<tr><td>Max Breadth (B) (m)</td><td>125</td></tr>
<tr><td>Max Height (H) (m)</td><td>50</td></tr>
<tr><td>Max Operational structure height above sea level ‘Freeboard’ (m)</td><td>30</td></tr>
<tr><td>Max Structure depth below sea level ‘Draft’ (m)</td><td>20</td></tr>
<tr><td>Max Footprint (m^2)</td><td>15,625</td></tr>
</table></td></tr>
<tr><td>Tension Leg Platform</td><td>A TLP is a semi-submerged buoyant structure, anchored to the seabed with tensioned mooring lines. The combination of the structure buoyancy and tension in the anchor / mooring system provides platform stability. This system stability (as opposed to the stability coming from the floating structure itself) allows for a generally lighter floating structure.

(Images indicative, geometry may change)</td><td><table>
<tr><th colspan="2">TLP</th></tr>
<tr><td>Max Length (L) (m)</td><td>125</td></tr>
<tr><td>Max Breadth (B) (m)</td><td>125</td></tr>
<tr><td>Max Height (H) (m)</td><td>70</td></tr>
<tr><td>Max Operational structure height above sea level ‘Freeboard’ (m)</td><td>30</td></tr>
<tr><td>Max Structure depth below sea level ‘Draft’ (m)</td><td>40</td></tr>
<tr><td>Max Footprint (m^2)</td><td>15,625</td></tr>
</table></td></tr>
</table>

5.4.3 Mooring Systems

5.4.3.1 Mooring options

The Carbon Trust Phase 1 Floating Wind Joint Industry Project Summary Report (Carbon Trust, 2018) identified an industry-wide need for innovation in the areas of floating wind moorings. As such the Offshore Development needs to maintain flexibility to capitalise on innovations in this area. Ultimately the final design of the mooring system will be selected as part of the overall 'system' optimisation during the Front End Engineering and Design (FEED) and detailed design phase.

Floating offshore WTGs need to maintain their position even during the most extreme events or energetic storms. The mooring and anchoring systems are responsible for the station-keeping of the floating structure.

The following provides a brief description of the mooring configurations considered. In general, all configurations can be utilised as a station-keeping system for all floating substructure types and the configuration will be selected following detailed design, based on the adopted substructure design, site conditions, and ground conditions. The only exception to this is the 'Tension Leg' configuration which is specifically designed for TLP substructures. Figure 5.5 illustrates the different mooring configurations considered.

> **Catenary mooring**: Steel chains and/or wires and in some cases synthetic elements whose weight in the water column provides the restoring force that holds the floating platform in place. A large section of the mooring chain rests on the seafloor removing any vertical load to the anchors and enabling conventional and more cost-effective anchor types (drag anchors) to be used. These systems typically have larger footprints but can be reduced through the attachment of clump weight and/or heavy chain sections to, predominantly, the sections of chain that rest on the seabed;

> **Semi-taut mooring**: A combination of synthetic fibres and steel chain, where the chain sections provide the restoring and anchoring benefits of the Catenary system and the synthetic fibres, under some tension, limit the amount of steel chain required, providing benefits in the overall footprint of the mooring system;

> **Taut spread mooring**: Synthetic fibres or wires with small link elements of chain arranged in a non-vertical configuration (unlike Tension Leg). The system is placed under significant tension to create a stable mooring system where all of the stability comes from the tension held within the taut mooring line; and

> **Tension Leg**: Specific to TLP substructures. Steel tendons or synthetic fibre wires arranged in a vertical, or near vertical, configuration under significant tension (against the buoyancy of the platform), provide a more stable platform but increase the complexity in the anchor design and installation and operations and maintenance techniques.

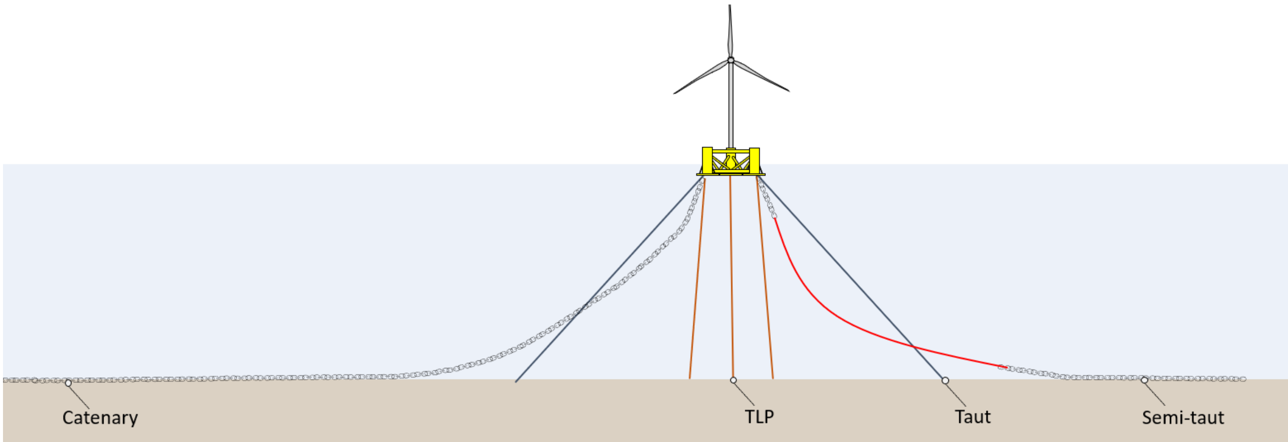


Figure 5.5 Illustration of potential mooring system configurations

5.4.3.2 Mooring components

The vast majority of mooring systems can be broken down into three key components (Figure 5.6):

- Anchor (see Section 5.4.4).
- Mooring line comprising of the following single or combined material solutions:
  - Steel Chains;
  - Steel Wire Ropes / Cables (multiple configurations); and
  - Synthetic Ropes, such as nylon, polyester, polypropylene, kevlar, and high-density polyethylene.
- Various connectors and ancillaries to connect the mooring components and adjust the behaviour of the system:
  - Long-term shackles / links;
  - Clump weights;
  - Buoys / buoyancy elements; and
  - Tensioners.

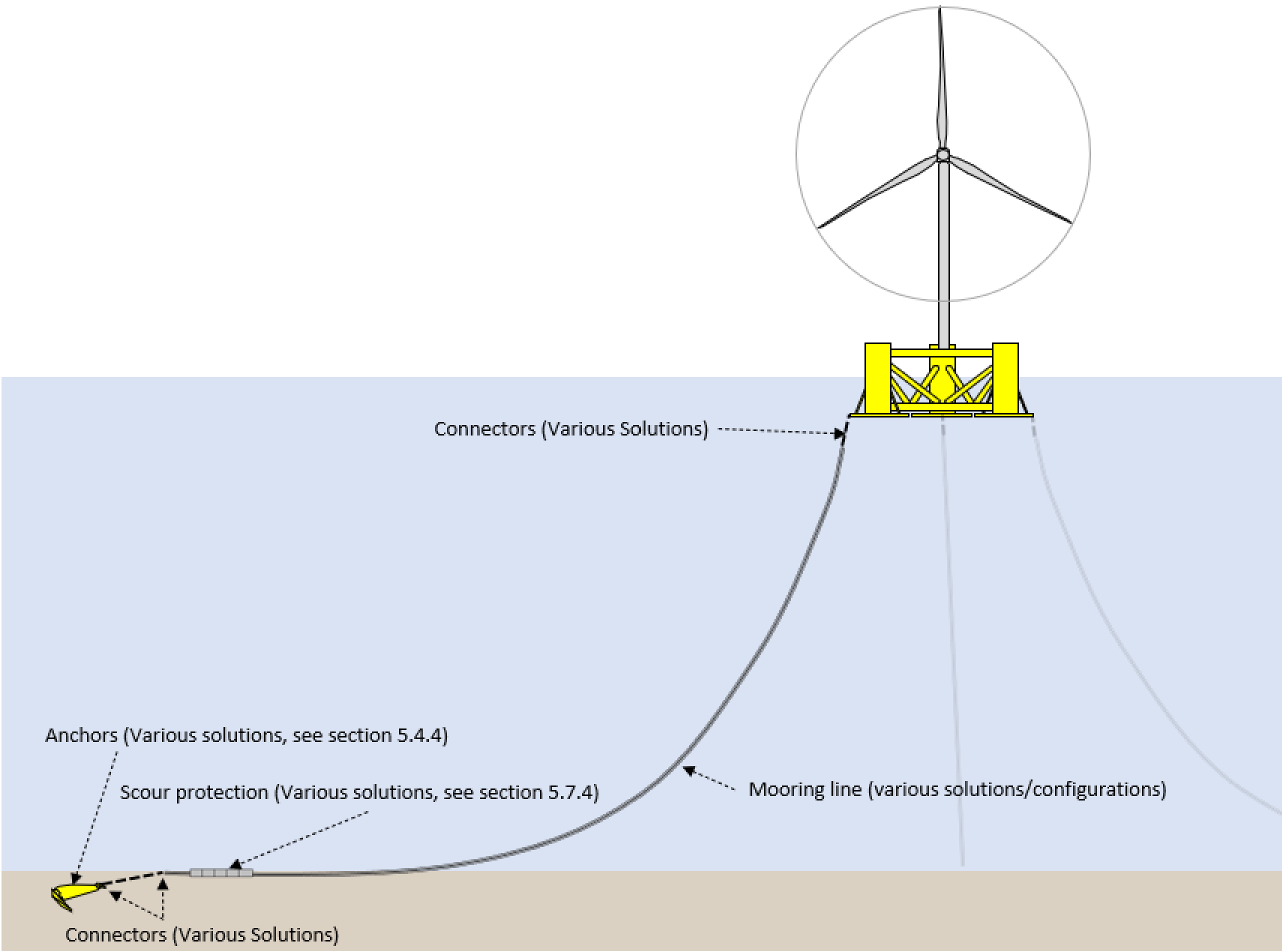


Figure 5.6 Key components of a typical mooring system

If a catenary mooring system is used, clump weights are likely to be required in order to add mass to the mooring line and dampen the lateral movement of the floating structure. These weights would be attached to each of the mooring lines and will be in the form of a casing around the mooring line where it meets the seabed (the touch-down point), with clump weights spread out along the grounded portion of the mooring chain and in some configurations extended into the water column. As the spread of the catenary mooring system is relatively large, HWL is looking at ways to reduce this, to reduce the seabed footprint of the Offshore Development. However, by narrowing the spread, the movement of the mooring lines increases and so more clump weights will be required to reduce this movement. The maximum length of the casing with clump weights is expected to be 360 m per mooring line with up to 40 clump weights spread evenly along the casing, resulting in one clump weight approximately every 9 m. It is possible smaller clump weights could be positioned closer together to provide the same effect but the feasibility of this will only be determined during detailed design.

5.4.3.3 Mooring design parameters

The exact dimensions and configuration of the mooring system to be used for the Offshore Development cannot be finalised at this stage due to procurement and supply chain considerations of emerging technology. However, Table 5.6 below details the worst case characteristics of the mooring systems considered.

Whilst it is anticipated that each WTG and floating substructure will require between three (i.e. one from each corner of a triangular substructure) to eight (i.e. two from each corner of a square substructure) mooring lines, there is the potential that due to the extreme sea conditions at the Offshore Development location, certain mooring solutions may require up to nine lines per substructure; this is therefore considered the worst case scenario for moorings and has been used in relevant impact assessments within this Offshore EIAR.

Table 5.6 Worst case design parameters for mooring systems

Mooring Parameter	TLP	Taut	Semi-taut	Catenary
Maximum number of moorings per WTG	9	9	9	9
Maximum mooring line length (m per line) (based on maximum water depth found within the Offshore Site of 102 m)	125	750	1,050	1,650
Maximum proportion of mooring line that may come into contact with seabed (%)	0	15	50	90
Area of seabed where lateral movement can occur by mooring line (km^2 per line)	n/a (no mooring line on seabed)	0.00000375	0.0315	0.035
Maximum spread radius of mooring lines (based on maximum water depth found within the Offshore Site of 102 m)	300	750	1000	1,500
Maximum number of clump weights per mooring line	n/a	n/a	40	40
Maximum seabed footprint of each clump weight (m^2)	n/a	n/a	2	2
Material of mooring lines	Steel or synthetic cables Connectors – Steel	Chains – Steel Cables – Steel Synthetic Rope – Nylon, Polyester or other synthetic equivalent Connectors – Steel	Chains – Steel Cables – Steel Synthetic Rope – Nylon, Polyester or other synthetic equivalent Connectors – Steel	Chains – Steel Cables – Steel Connectors – Steel
Maximum thickness of mooring lines	0.8 m	Chains – 175 millimetres (mm) Synthetic – 350 mm	Chains – 175 mm Synthetic – 350 mm	Chains – 175 mm

5.4.3.4 Mooring layout

Figure 5.7 illustrates an indicative mooring layout, showing a triangular substructure utilising three mooring lines. One possible mooring system optimisation is the use of shared mooring anchor points as seen in Figure 5.7. This approach can lead to a potential reduction in material and installation costs, whilst also reducing the level of seabed disturbance. However, this approach is subject to technical feasibility.

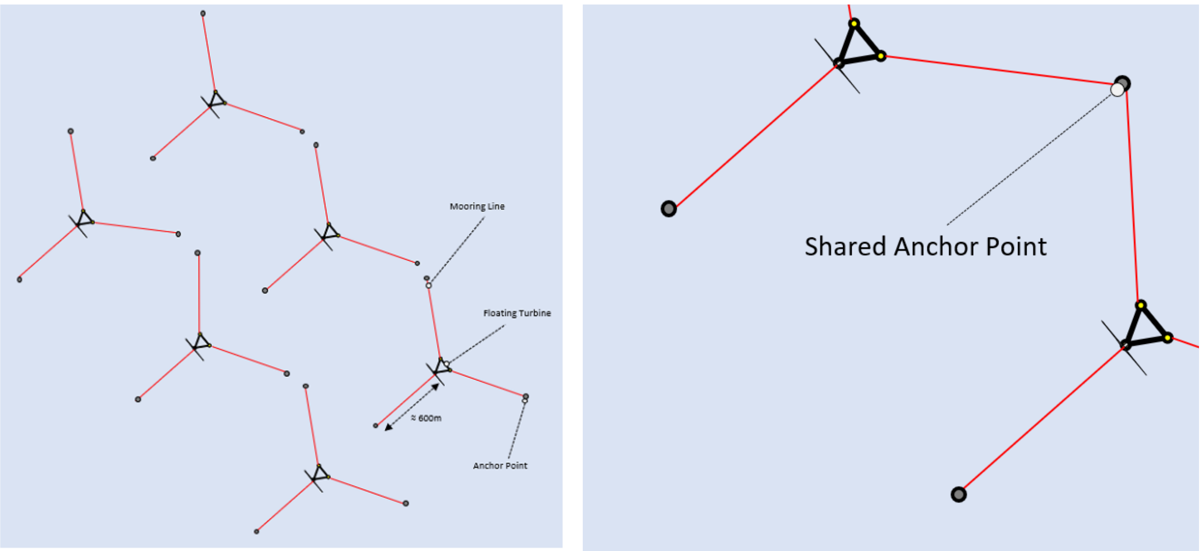


Figure 5.7 Example of a typical mooring layout (left) and shared anchor point (right)

The point of connection of the mooring lines to the substructures will be dependent on the mooring system and the type of substructure ultimately selected for the Offshore Development, which will be further refined through detailed design. The connection point may be at the bottom of the substructure as shown in Figure 5.9, and Figure 5.10, therefore, up to 20 m below sea level for the semi-submersible substructures or up to 40 m below sea level for the TLP. Depending on the final design, however, it could be closer to the sea surface. The variations in the mooring system configuration and connection point to the substructure mean that the proportion of each mooring line that is close to the sea surface will differ considerably depending on the selected solution. This has implications on the level of interactions with vessels (termed under-keel clearance) and this impact is discussed and assessed further in Chapter 14: Shipping and Navigation.

5.4.3.5 Excursion

All floating substructures will have a defined design coordinate within the Development, Specification, and Layout Plan (DSLP). A (yet to be determined) element of the structure will be designated as the reference point to align with the design coordinate. The substructure and mooring system will be installed such that the reference point in the structure aligns with the design coordinate in calm sea states. However, the substructure will offset from its design coordinate (excursion) depending on the magnitude and direction of wind, sea, swell and current conditions as illustrated in Figure 5.8. The extent of excursion differs depending on a number of design factors but predominantly foundation geometry and mooring configuration and type. Under normal operation (i.e. a fully intact mooring system), substructure excursions will be up to a maximum of 75 m in the most extreme conditions the mooring system is designed for. In the event of mooring line failure, substructure excursions may exceed this value; however, the extent of excursion will be dependent on the final design adopted.

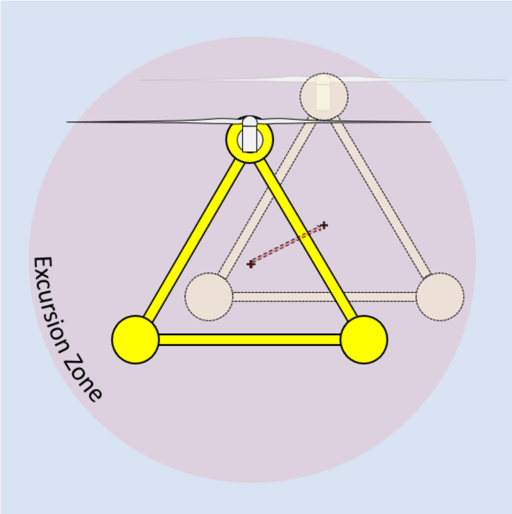


Figure 5.8 Floating structure excursion (illustration)

5.4.4 Anchors

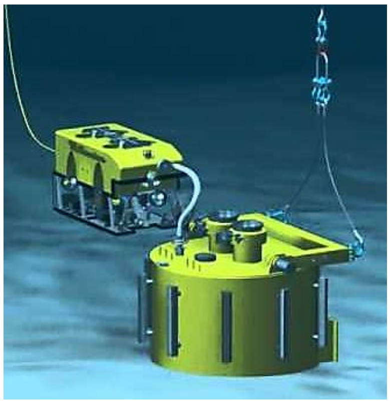
5.4.4.1 Anchor options

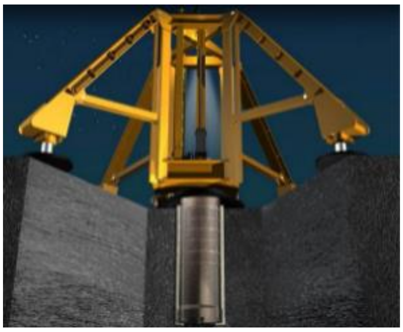
A variety of anchor options are currently being considered for the Offshore Development; the final selection will depend on the mooring configuration, seabed conditions and holding capacity required for each of the substructures. Catenary mooring configurations will often use drag-embedded anchors to handle the horizontal loading, though piled, suction bucket, and gravity anchors are still applicable, whilst taut-leg moorings will typically use either suction piles or gravity anchors to cope with the large vertical loads placed on the mooring and anchoring system. The size of the anchor is also variable, with larger and heavier anchors able to generate a greater holding capacity which might be required to withstand the extreme environmental conditions at the Offshore Site.

An overview of anchor options and their suitability with different mooring types is presented in Table 5.7.

Table 5.7 Overview of anchor options and suitability with different mooring types

Anchor Type	Description	Suitability for Mooring Option	Image
Gravity	Buried to a depth depending on the weight, geometry, and soil characteristics of the site. The holding potential of the anchor is proportional to the weight. Gravity anchors require medium to hard soil conditions.	Mainly used with taut and semi-taut mooring systems, but can be used with catenary moorings.	 (Image from FMGC)

Anchor Type	Description	Suitability for Mooring Option	Image
Drag Embedment	Installed by being dragged along the seabed until it reaches the required depth and holding capacity. It uses soil resistance to hold the anchor in place. Best suited for cohesive sediments and function best when they are fully submerged into the seabed. Where the seabed is stiff clay or sandy, there can be limited penetration.	Mainly used for catenary moorings where the mooring line is horizontal to the seabed; drag embedment anchors are not suited for any vertical loading.	 (Image from Vryhof)
Vertical Load	Vertical load anchors are similar to drag anchors and are installed by dragging along the seabed. These can also be installed via a suction embedded method.	Mainly used for catenary moorings, however, in contrast to drag anchors, vertical load anchors can withstand both horizontal and vertical loading.	 (Image from Vryhof)
Suction Bucket	Suction bucket technology (also known as suction anchors, suction piles, or suction caissons). Involves an upside-down capped steel cylinder that is sucked into the seabed by pumping out the water. It is only feasible in particular seabed types, including sands and clays. The technology was originally developed in the oil and gas industry in recent decades and was used as the anchor solution for the Hywind Floating Offshore Windfarm in Scotland. The main benefit of suction buckets is the avoidance of piling and the associated noise impacts.	Mainly used with taut and semi-taut mooring systems.	 (Image from Oceaneering)

Anchor Type	Description	Suitability for Mooring Option	Image
Drilled Piles	Depending on the soil and the metocean conditions at the PFOWF Array Area, a drilled pile mooring system may be needed. Instead of driving a pile into the seabed, a pile or ground anchor is drilled into the seabed using a subsea drill rig and then sealed with grout. The drill rig required to complete the drilling activity can either be a subsea drill rig or drill rig deployed from the vessel deck.	Mainly used with taut and semi-taut mooring systems, but can be used with catenary moorings.	 (Image from Blade Offshore Remote Drilling)
Screw Piles	Screw (helical) piles are foundations that are screwed into the ground. Screw piles generate less noise and vibration during installation than impact piles. However, their use is subject to seabed sediment conditions.	Mainly used with taut and semi-taut mooring systems, but can be used with catenary moorings.	
Impact / Driven Piles	Impact piles are foundations that are driven into the seabed using a percussive pile-driving hammer. The hammer type and size, size of the pile, and soil properties influence the number of blows and time required to achieve the target penetration depth.	Mainly used with taut and semi-taut mooring systems, but can be used with catenary moorings.	

5.4.4.2 Anchor design parameters

The type of anchors or piles that will be used for the Offshore Development cannot be finalised at this stage due to ongoing engineering design studies to determine the suitability of each option for the ground conditions and the mooring technology to be used. However,

Table 5.8 details the general worst case characteristics of each of the anchor types being considered. Additionally, worst case parameters are provided for the installation of impact (driven) piles and these are set out in Table 5.9. Further information on piling parameters is provided in Offshore EIAR (Volume 3): Appendix 10.1: Underwater Noise Modelling.

As with the mooring systems, it is anticipated that each WTG and floating substructure will require between three to eight mooring lines and therefore a similar number of anchors / piles. However, there is the potential that due to the extreme conditions at the Offshore Site, up to nine mooring lines per substructure may be needed and therefore up to nine anchors / piles would be needed; this is considered the worst case scenario for anchors and has been used in relevant impact assessments within this Offshore EIAR.

Table 5.8 Worst case design parameters for anchors

Parameter	Drag Embedment	Gravity	Vertical Load	Suction Bucket	Drilled Piles*	Impact / Driven Piles
Number of anchors per WTG	9	9	9	9	9	9
Anchor / pile length (m)	20	25	20	15	80	25
Anchor width (m)	10	25	10	n/a	n/a	n/a
Anchor / pile diameter (m)	n/a	n/a	n/a	10	3	5
Anchor height (m)	10	5	10	n/a	n/a	n/a
Seabed footprint per anchor (m^2)	200	625	200	78.5	7.1	19.6
Burial depth (m)	20	1	20	14.5	75	20
Anchor height above / below seabed (m)	-10	4	-10	0.5	5	5
Distance anchors may be dragged during installation (m)	50	n/a	50	n/a	n/a	n/a
** Note: the required drilled pile length reduces as the pile diameter increases. For modelling purposes, the worst case in terms of drill arisings and underwater noise uses a maximum pile diameter of 3 m and a maximum burial depth of 49.5 m.*						

Table 5.9 Worst case design parameters for impact piles

Parameter	Pile Scenario
Maximum pile diameter (m)	5
Maximum hammer energy (kilojoules)	2,500
Maximum number of piles installed per day	3
Minimum number of piles installed per day	1
Maximum duration (days) of piling operations	63

5.5 Offshore Transmission Infrastructure

5.5.1 Inter-array Cables

The inter-array cables on an offshore wind farm collect the power from the WTGs and either connect to an offshore substation, which is directly connected to shore, or may connect to a wider offshore network, as the industry starts to build out offshore meshed solutions. In the case of the Offshore Development, the Offshore Site's small scale and proximity to shore remove the necessity for any wider network or an offshore substation platform. It is anticipated that the voltage level of the inter-array cables will be 66 kV.

One of the key design differences between the inter-array and offshore export cables for a fixed-bottom wind farm development and those for floating WTGs is the dynamic nature of the cables. The cable system must be able to accommodate the movement of the floating substructure without imparting any direct loads on the cables (i.e. acting as a form of mooring). As such, the cable design often adopts a 'lazy-s' configuration using buoyancy modules attached to a portion / midpoint of the cable. Although other configurations may be adopted for the same purpose, the 'lazy-s' allows the cable configuration to expand and contract in shape, in response to the movements of the floating substructure. An illustration of a typical dynamic cable arrangement is provided in Figure 5.9.

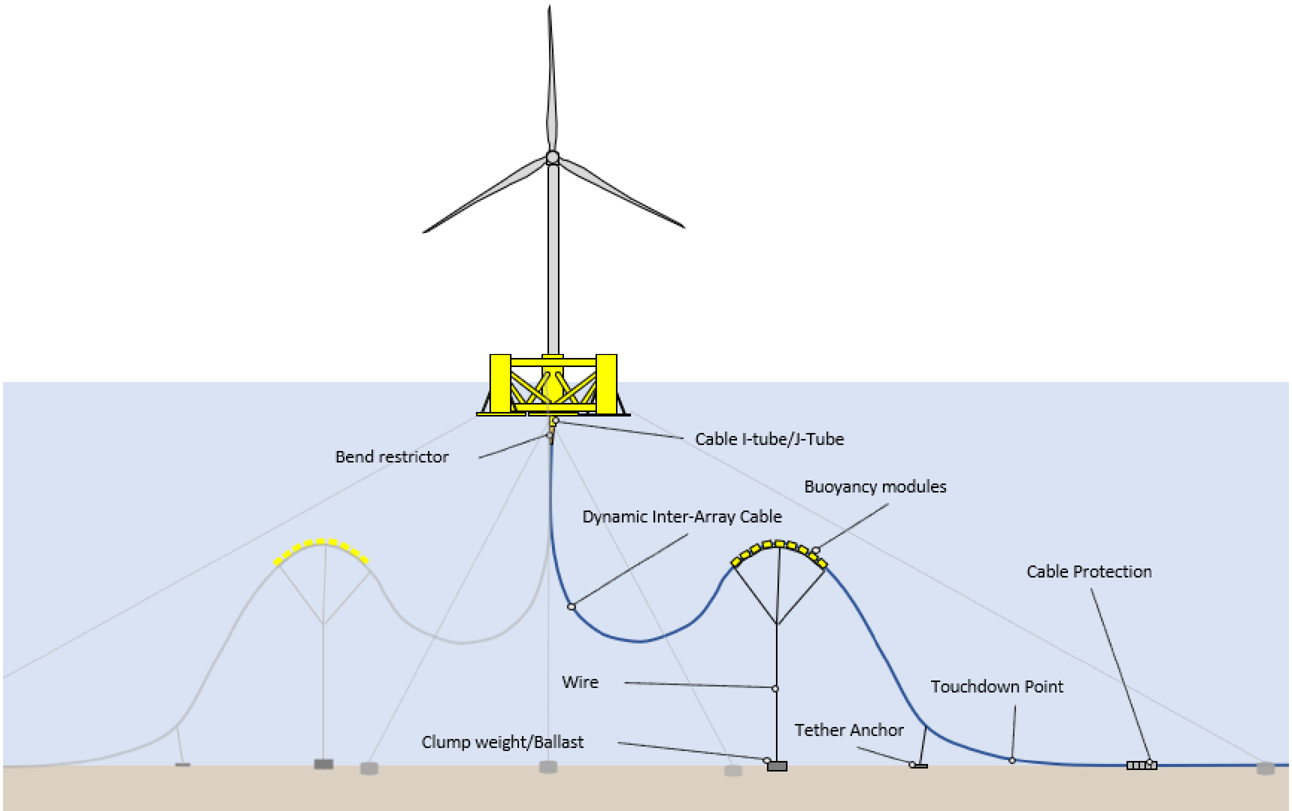
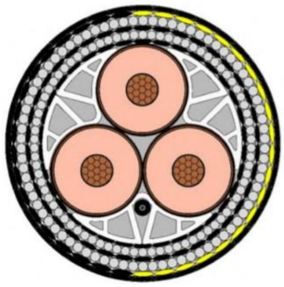
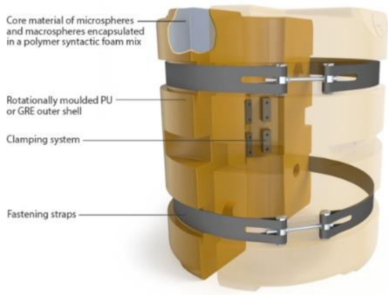


Figure 5.9 Typical dynamic cable arrangement

Table 5.10 provides further detail on some of the key features of dynamic inter-array cables.

Table 5.10 Dynamic inter-array cable features

Cable Feature	Description	Image
Dynamic Cable	Typically consists of the following composition in order of inside to outside (it should be noted that there can be variance in the cable make-up depending on the specific supplier and/or project-specific requirements / design): > Three-phase conductor (typically copper); > Conductor insulation; > Conductor sheath; > Filler; > Optical fibre; > Inner sheath (bedding); > Armour wire (multiple layers depending on design); and > Outer jacket.	
Buoyancy Module	The buoyancy modules are typically clamped to the cable during installation and serve to support the weight of the cable catenary in the water column and are designed and positioned to provide the 'lazy-s' configuration in the water column. The number of modules required will be driven by a combination of factors such as: > Water depth; > Desired configuration; > Environmental conditions; > Metocean conditions; > Dynamic cable specification amongst other drivers; and > Floating sub-structure movement.	 (Image from Balmoral Offshore)
Bend Restrictor	Bend restrictors are used to reduce the fatigue in the inter-array and offshore export cables at pinch points within the system's physical design. This is particularly pertinent in the case of the floating WTG design as there are two moving components, the cable systems and the floating structure, as opposed to just the cable system in the case of the fixed-bottom WTG arrangement. For the dynamic cable design, a bend restrictor may be used at the exit point of the cable from the floating structure and at the touchdown / tie-down point of the cable on the seabed, although this is designed on a project-by-project basis. The bend restrictor material type is typically non-toxic polymers.	 (Image from Balmoral Offshore)

Much like the mooring systems, there is significant scope for innovation in the area of dynamic cables in the offshore wind industry, and as such the Offshore Development needs to maintain flexibility to capitalise on innovations that may arise during the development phase. The overall design and specification within the Design Envelope allow for development during the FEED and detailed design phases. Figure 5.10 and Table 5.11 provide details of the Design Envelope associated with the dynamic cables.

As can be seen in Figure 5.10, from the point where no movement in the cable is expected on the seabed (the static cable) each inter-array cable will be laid on the seabed, either in a trench or buried; where burial is not achievable, cable protection measures will be used and placed over the top of the cable. The inter-array cables will link the WTGs together in an array configuration. From the final WTG in the sequence, an offshore export cable will export the electricity generated back to shore.

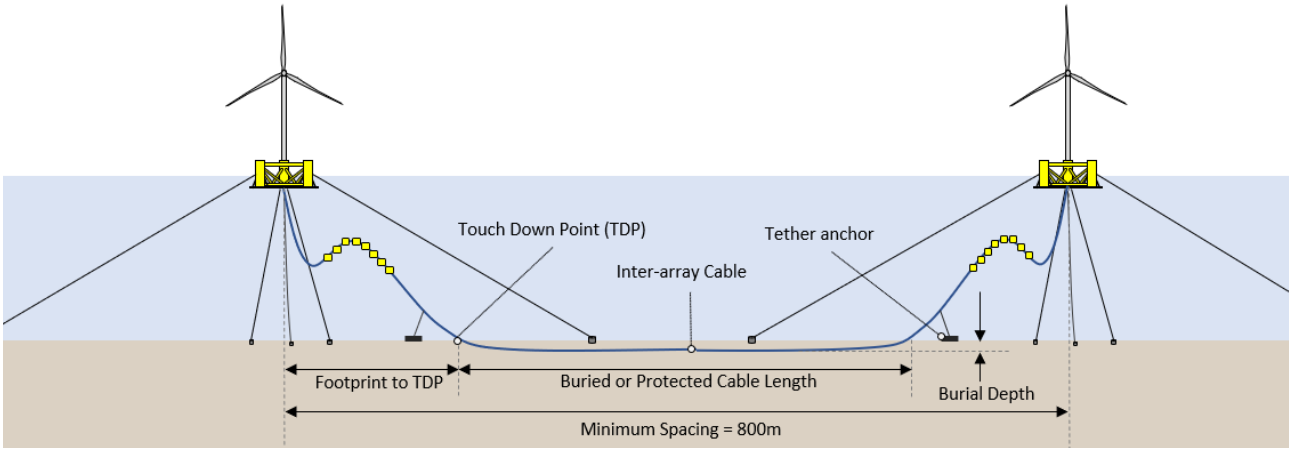


Figure 5.10 Dynamic inter-array cable dimensional characteristics (for illustrative purposes)

To restrain the movement of each of the dynamic inter-array cables an anchor may be attached at the end of each cable prior to the transition to the seabed laid section. The anchors will be gravity-based structures (see Figure 5.11) that will be laid on the seabed and tethered to the cable close to the touch-down point (TDP) as shown in Figure 5.10. There may be one tether anchor installed either side of the buried cable section, so there will be two anchors per inter-array cable between WTGs. Clump weights may be placed on top of each anchor (and consequently have no interaction with the seabed) to provide additional ballast and restraint depending on the site conditions.

Figure 5.11 Typical anchor structure to be deployed on inter-array cables

Table 5.11 Worst case design parameters for the dynamic inter-array cables

Parameter	Value (Maximum or Range)
Maximum number of inter-array cables	7
Maximum voltage	110 kV
Maximum external cable diameter	300 mm
Maximum footprint of the dynamic / floating portion of each cable to touchdown point on seabed	500 m
Maximum cumulative length of inter-array cables on seabed	Up to 20 kilometres (km)*
Maximum cumulative length of inter-array cable system	Up to 25 km**
Maximum trench width	Up to 3 m (dependent on installation methodology)
Maximum temporary zone of influence during cable installation	Up to 15 m*** (dependent on installation methodology)
Target depth of lowering	0.6 m to 1.5 m, where technically possible****
Maximum length of cable requiring additional cable protection	Up to 50% of seabed laid cable, 10 km (if deemed a requirement) *****
Maximum number of anchors per dynamic cable	Up to two anchors for each cable between WTGs
Maximum seabed footprint per tether anchor	20 m^2

** Dependent on the distance between WTGs and the number of WTGs installed.*
*** Inter-array cable length of 25 km incorporates the combined length of two cables per WTG (dynamic and static) and additional length to account for dynamic cable movement.*
**** The area of the seabed that may experience some level of compaction or disturbance due to the footprint of the cable laying equipment (plough or Remote Operated Vehicle [ROV] tracks).*
***** The exact target depth of lowering will be based on a CBRA with consideration of seabed conditions and potential threats to the cables and may vary throughout the Offshore Development.*
****** HWL will aim to maximise achievable protection by burial, but allowance is made for cable protection where burial is not possible.*

5.5.2 Offshore Export Cable(s)

As the offshore export cable(s) will connect directly to the first WTG in the array configuration, the first section will also be in the water column and dynamic. Consequently, it will share many of the key components of the dynamic inter-array cable as discussed in Section 5.5.1 and Table 5.11. The following key differences are noted:

> Offshore export cable cross-sectional area will likely be greater but will likely remain at the same voltage as the inter-array cables;

> Offshore export cable(s) will be High Voltage Alternating Current (HVAC);

> As a result of the above the installation ancillaries (bend restrictors, buoyancy modules), may be larger to accommodate the greater dimensions and associated weight;

> Offshore export cable(s) will have a dynamic to static transition as part of the cable design;

> Offshore export cable(s) length will be significantly longer than that of the inter-array cables; and

> The landfall end of the offshore export cable(s) will be installed with a specifically designed pulling head or the cable fixed with a cable 'sock' to facilitate the pull of the offshore export cable(s) into the onshore joint bay.

Figure 5.12 and Table 5.12 provide details of the Design Envelope associated with the offshore export cable(s).

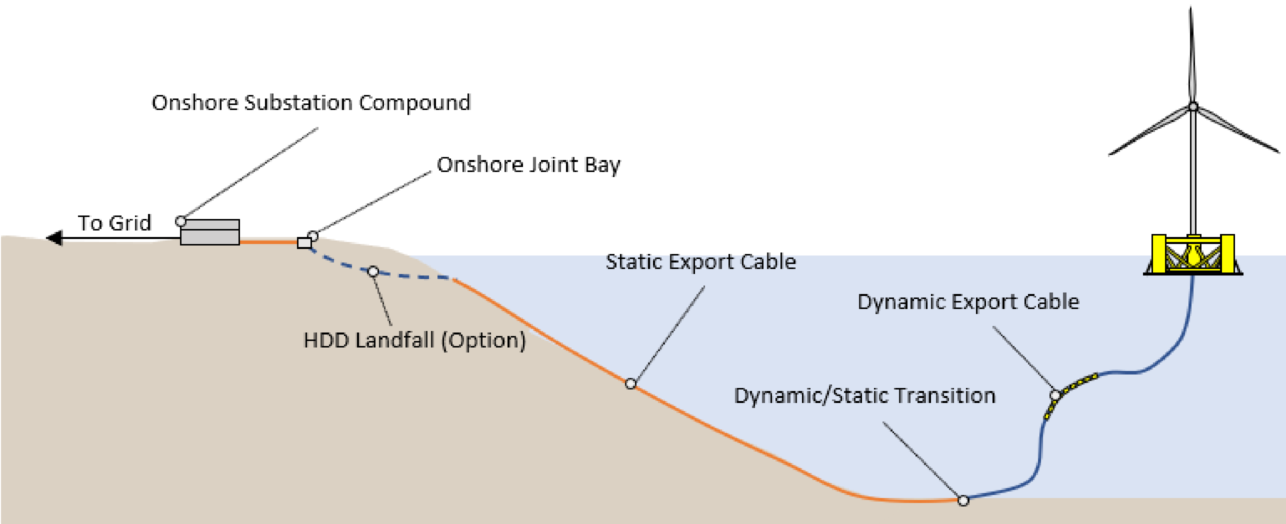


Figure 5.12 Key elements of a floating wind farm offshore export cable

Table 5.12 Worst case design parameters for the Offshore Export Cable(s)

Parameter	Value (Maximum or Range)
Maximum number of offshore export cables / trenches	Up to two cables in separate trenches*
Maximum cable voltage	110 kV **
External cable diameter	300 mm***
Maximum footprint of the dynamic / floating portion of the Offshore Export Cable(s) to touchdown point on the seabed	500 m
Maximum cable length on the seabed (per offshore export cable)	12.5 km (25 km in total for two cables)
Maximum trench width	3 m (dependent on installation methodology)
Maximum temporary zone of influence during the Offshore Export Cable(s) installation	15 m**** (dependent on installation methodology)
Target depth of lowering	0.6 m to 1.5 m, where technically possible*****
Maximum length of Offshore Export Cable(s) requiring additional cable protection	The target is to permanently bury 100% of the cable in the seabed (noting the TDP of the dynamic section of cable will change as it can rise / fall in the tide) and use cable protection where sufficient burial is not achieved. Cable protection requirements could account for 50% of the cable length as a worst case.

** If two offshore export cables are required (this will be dependent on the capacity of the dynamic section of the offshore export cables), they will be installed in separate trenches within the OECC. The distance between the trenches will vary and will generally reduce as the cables approach the landfall but a minimum separation distance of 20 m is anticipated.*
*** A typical HVAC cable will be around 300 mm in diameter and will comprise three copper or aluminium conductor cores with polymer insulation and a fibre optic cable bundle. The cable will be insulated, sheathed, and armoured (as presented in Table 5.9).*
**** The area of the seabed that may experience some level of compaction or disturbance due to the footprint of the cable laying equipment (plough or ROV tracks).*
***** The exact target depth of lowering will be based on a CBRA with consideration of seabed conditions and potential threats to the cable and may vary throughout the Development. The offshore export cable(s) will be protected, wherever possible via burial, in line with a CBRA. Where sufficient burial cannot be achieved, other external cable protection measures will be utilised.*

5.5.3 Electromagnetic Fields

The Earth has its own geomagnetic field, meaning that electromagnetic field (EMF) effects are always naturally present, and this is known to vary between 25 microtesla (μT) and 65 μT (National Oceanic and Atmospheric Administration [NOAA], 2021a). A reference magnitude of the Earth's magnetic field at a particular location can be estimated from models publicly available (NOAA, 2021b). For the PFOWF site, from sea level to the maximum water depth, the naturally occurring geomagnetic field is estimated as 50.7±0.14 μT using the NOAA database.

Cables used for power transfer are known sources of additional EMF, creating a highly localised change in electric and magnetic fields. The voltage, size, and operational characteristics of inter-array and offshore export cable(s) differ from one another and between offshore wind energy project designs, and these all influence the level of additional EMF locally. HWL has commissioned Prysmian Group to undertake an initial modelling exercise of the predicted EMF from the offshore export cable(s) and inter-array cables, to determine the realistic worst case EMF associated with the project cables. The results of the modelling are presented in Table 5.13 and Table 5.14 below. Table 5.13 presents EMF levels for buried cables (to the minimum target depth of 0.6 m) and Table 5.14 presents EMF levels for dynamic sections of cables (which are not buried and are present in the water column, with protection).

Whilst offshore export cables and inter-array cables may be rated up to 110 kV, the worst case cable voltage for potential EMF effects is 66 kV. Potential magnetic fields generated are proportional to cable current and higher cable voltage results in a smaller cable current, whilst lower cable voltages result in larger currents and therefore higher levels of EMF and thermal loads.

The modelling undertaken demonstrates that EMF levels will be well below the natural variation of the earth's magnetic field for both seabed laid and in-water dynamic cables at this location. EMF levels dissipate rapidly from the source for both buried and dynamic cables. Levels of EMF are modelled at 17.1 μT at 0.6- m minimum burial depth and 3.21 μT at a 1-m distance from cables within the water column. Due to the dynamic nature of these cables, it is highly unlikely that receptors will come within, or remain in, close proximity to the cables. Should two 66-kV offshore export cables be installed, the anticipated separation distance between cables (20 m) means there will be no potential interaction between EMF effects.

Table 5.13 EMF levels at various distances from buried cable

Component	5 m	1 m	Seabed (cable buried to a minimum of 0.6 m)
Inter-array and Offshore Export Cables	≈0 μT	0.73 μT	17.10 μT

Table 5.14 EMF levels at various distances from the dynamic cables in the water column

Component	10 m	5 m	1 m
Inter-array and Offshore Export Cables	≈0 μT	≈0 μT	3.21 μT

5.6 Other Offshore Infrastructure

In addition to the already deployed LiDAR (Light Detection and Ranging) buoy at the Offshore Site, it is anticipated that up to five further buoys may be required across the site, these would consist of a wave rider buoy and marker buoys. The number and location of the marker buoys to be deployed will be determined in consultation with the Marine Coastguard Agency (MCA).

These buoys would be attached to the seabed using mooring devices such as common sinkers (small blocks of heavy material such as concrete, steel, etc.) or anchored through regular anchors. They could have one single mooring point or several points (up to three).

5.7 Offshore Installation and Commissioning

5.7.1 Pre-construction Surveys

Site-specific geophysical and geotechnical surveys were undertaken in Summer 2021 to inform detailed design and array layout. Further geophysical and geotechnical surveys are planned to be undertaken during 2022 and 2023 to provide further seabed information.

Additionally, an unexploded ordnance (UXO) survey using a magnetometer will be undertaken in Summer 2022 to identify any UXO that may need to be avoided by minor re-routing of the cables, or minor modifications of the anchor positions. Multibeam echo sounder (MBES) and side scan sonar may also be required. Based on an initial desk-based UXO assessment undertaken by Ordtek (Ordtek, 2021) it is assumed that it will be possible to avoid any UXO encountered during the survey. Should any further mitigation be required, such as clearance or detonation, this would be subject to separate assessment and licence applications.

Pre-installation surveys will then be undertaken in 2025/26. These will consist of visual inspections (using remotely operated vehicles [ROVs]) of the mooring locations and cable routes to confirm the exact routing and determine the need for any seabed preparation. These are likely to be undertaken between April and October when the weather is most suitable for offshore operations at the Offshore Site. These surveys are likely to take two to three days across the whole site, excluding any downtime for weather delays. Potentially MBES may also be needed, but this will be determined during detailed design.

All survey equipment will utilise ultra-short baseline positioning equipment to ensure precise subsea locations.

5.7.2 WTGs and Floating Substructures

Specific details on WTG installation will vary depending on the specific floating technology adopted and may change due to improvements in both the technology and supply chain. Components will be manufactured at a location dependent on technology and local supply chain offerings. If not fabricated at the assembly location the WTG and substructure components will be transported by sea to the assembly port. The same port is likely to be used for marshalling the other Offshore Development components such as the anchors and cables.

The substructure will be assembled at the quayside either onshore, in a dry dock or on a semi-submersible barge, depending on technology-specific installation requirements. Each WTG will be assembled and installed on the substructure at the quayside using a crane. Quayside pre-commissioning will take place to reduce offshore operations to a minimum. The complete WTG and substructure assembly is then towed to site where it is hooked up to the pre-installed mooring system (see Section 5.7.3). The inter-array cables (sometimes pre-installed) are laid and hooked up to the WTG. The WTG is then commissioned and released for automatic, unattended operation.

5.7.3 Mooring System

The mooring system installation and commissioning sequence will vary significantly depending on the mooring design adopted. Typically, to ensure efficient installations and avoid any simultaneous vessel operations, the mooring system will be installed and wet-stored prior to the floating assembly arriving in the field. The installation operation will vary depending on the type of mooring design selected, both in materials required (chain, fibre rope, hybrid, etc.) and configuration (catenary, taut, etc.), the options of which are detailed in Section 5.4.3.1.

A general installation sequence will involve anchor installation (see Section 5.7.4) prior to mooring installation, moorings will then be hooked to these pre-installed anchors and if required, hooked up to buoys which will act as future installation aids for the floating assembly hook-up. Upon the arrival of the floating assembly, the substructure will be manoeuvred into the correct location using tugboats to steer the substructure into position / orientation whilst the previously installed mooring is connected to the floating substructure.

5.7.4 Anchors and Scour Protection

5.7.4.1 Installation operations

The anchor installation methodology will heavily depend on the specific methodology adopted. For the more technologically basic solution, such as gravity and drag anchors, the installation equipment will typically be limited to a crane and installation vessel. For the drilled and screw pile solutions more specialist equipment is required such as work class ROVs and screw piling spreads on a dynamically positioned (DP) installation vessel. Likewise, for the impact pile solution, a larger DP construction vessel will be needed, to provide a stable platform on site from which the piling can take place; the water depth within the PFOWF Array Area is too deep for a jack-up vessel, which is currently limited to water depths in the region of 60 m.

Depending on the anchor solution selected there may be a requirement for seabed preparation prior to installation of the anchors. This may take the form of seabed levelling, dredging of the soft mobile sediments and/or boulder removal within the vicinity of the anchor footprint. Should boulders require removal, this will be achieved using a boulder clearance plough or grab unit lowered from a vessel, with the boulders being removed to a suitable distance from the anchor location to facilitate safe and efficient installation. For some anchor solutions such as gravity base, the installation of a gravel bedding and levelling layer may also be required. Dredging would be carried out by dredging vessels using suction hoppers or similar, and the spoil is likely to be used as backfill material around the anchors. It is assumed that it will be possible to avoid any UXO encountered during the survey. Should any further mitigation be required, such as clearance or detonation, this would be subject to separate assessment and licence applications. The requirement for any of the above preparatory works would be informed by the choice of anchor solution and by detailed analysis of the site-specific geophysical and geotechnical surveys undertaken in Summer 2021, as well as the further geophysical and geotechnical surveys that are planned to be carried out in 2022 and 2023. A summary of the different anchor technologies and likely installation sequence is set out in the following sections.

5.7.4.1.1 Gravity anchor

Gravity anchors are concrete or concrete-steel hybrid structures, often including additional ballast (typically sand, gravel, rock, or dredged material) that sit on the seabed, using their own weight to maintain position. If used, these anchors are lowered to the seabed in the required location from the back of a vessel.

5.7.4.1.2 Drag embedment anchor

Drag embedment anchors are designed to penetrate approximately 10 m to 15 m into the seabed, subject to seabed conditions. The anchors would be installed by an Anchor Handling Tug Supply (AHTS) vessel, which will lower the anchor to the seabed and then drag it into the required position and depth; this method disturbs the seabed as the anchor is dragged creating a temporary seabed disturbance corridor the width of the anchor for approximately 50 m.

5.7.4.1.3 Vertical load anchor

These anchors are installed in a similar fashion to drag embedment anchors.

5.7.4.1.4 Suction bucket

Suction bucket anchors are lowered to the seabed from a vessel using a crane. Depending on the ground conditions, the suction bucket is then either pushed into the seabed or a negative pressure is created within the skirt by a pipe that is used to pump water out of the suction bucket.

5.7.4.1.5 Impact (driven) piles

If impact piling is the selected anchor solution, this would involve striking the pile into the seabed with a hydraulic hammer to the required design depth. Operations would include a 20-minute ‘soft start’ where the hammer energy will be kept at a minimum of approximately 10% maximum energy before being gradually increased during the piling operation to maintain a sufficient rate of penetration. Depending on the soil conditions encountered, maximum hammer energy may only be required at the later stages of the piling operation. The maximum installation parameters for hammer / impact piling are presented in Table 5.9 above.

5.7.4.1.6 Drilled / screw piles

If ground conditions rule out the possibility of impact piling due to the presence of rock or hard soils, the screwed or drilled pile options may be chosen. Screw (or helical) piles are foundations which are screwed into the ground. To install screw piles torque devices will be used to effectively screw the anchors into the seabed to the required depth. Drilled piling methods use drill bits to drill through the rock to the required depth, with a casing installed as the borehole is created. Compressed air or water is used to flush cuttings from the borehole; these will be discharged at the seabed around the borehole. The sediments drilled from each pile will be up to a maximum of 350 cubic metres (m^3); these will be either in the form of large clasts deposited on the seabed in the immediate vicinity of the drilled hole or disaggregated and dispersed within a sediment plume near the seabed. It is expected that the drilled cuttings will be a combination of these two forms. Once the drilling is complete and the casing installed, the pile will be installed in the borehole which will then be sealed with grout to provide additional stability and strength. The grout (an inert cement mix) will be pumped either from the installation vessel or a support vessel. As per the embedded mitigations discussed in Section 5.3.3 best practice mitigation will be implemented to minimise the amount of drill mud / cuttings released during this process to ensure minimal grout is lost to the surrounding environment.

5.7.4.2 Scour protection

There may also be a requirement to install scour protection post-installation for some anchor solutions to prevent the structure from being undermined by sediment processes and seabed erosion. The requirement for scour protection may be included in the design process or in reaction to the identification of an issue as part of the periodic inspections undertaken during operation and maintenance as outlined in Section 5.10.

Typical scour protection solutions include:

- Rock placement
  - This is achieved either through a fall-pipe from a rock placement vessel (most efficient method and generally used in water depths greater than 10 m) or directly placed with a grab device that lowers the rock to the seabed (used in shallower waters). Graded rock is used with grain sizes being tailored to achieve the necessary protection;
- Concrete mattress protection
  - Mattresses are generally made of small concrete blocks connected with a mesh of polypropylene rope, which will conform to changes in seabed morphology. Bevelled elements are used on the edges to create a sloped profile against the seabed. Where appropriate, mattresses fitted with polypropylene 'fronds' can be used to enhance the protection provided. The fronds encourage sediment deposition, in the best case creating a protective sandbank over the mattress. Mattresses require placement either by divers or an ROV to ensure that they are positioned correctly;
- Sand- / grout-filled bags
  - The placement of sand or grout bags over the cables is essentially a smaller-scale version of concrete mattresses. They are either pre-filled or placed on the seabed empty and then inflated with structural grout from a pumping spread on a vessel, coordinated by a diver or an ROV. The grout cures to provide an effective over cover protection system for the cables;
- Filter unit / rock bags
  - Filter unit / rock bags made of a non-corrosive and a rot-proof polyester mesh capable of containing 2, 4, or 8 tonnes of rock used as remedial scour protection or stabilisation medium. The rock bags are filled onshore and shipped offshore for deployment by crane;
- Frond mats
  - Mats, which mimic natural seaweed, can provide scour protection for offshore wind farm foundations. The mats are typically composed of a concrete mattress, covered with a high tensile strength polypropylene layer with buoyant fronds (leaf-like) lines. Like seaweed, these fronds provide additional drag and slow the flow of water, thereby reducing the sediment carrying capacity of the water and encouraging sand, silt, or soil to be deposited onto the mat. This immediately begins to build up on the frond mattress, forming a permanent, natural, fibre-reinforced sandbank, to protect the area around the anchors. These are likely to be lowered to the seabed from a vessel and then secured into position by divers or ROV; and
- Partial or full backfill using previously excavated seabed materials
  - As described in Section 5.7.4.1 above, excavated material would be re-deposited around the anchors where practicable.

Table 5.15 details the worst case requirements for seabed preparation and scour protection. The minimum separation distance between the anchors on the seabed will be such that it negates the coalescence of scour pits from each anchor, which would ultimately lead to the development of global scour. The exact separation will be determined during detailed design; however, it is not envisaged that anchors will be installed within the worst case scour extent informed through equilibrium calculations of scour processes, due to risks to asset integrity from global scour.

Table 5.15 Seabed preparation and scour protection requirements

Anchor Solution	Seabed Preparation Required		Scour Protection Required			
	Type	Maximum seabed footprint per anchor (m^2)	Type	Height of scour above seabed (m)	Max volume of scour protection per anchor (m^3)	Maximum seabed footprint of scour protection per anchor (m^2)
Gravity	Seabed levelling	900	All types to be considered.	1	260	260
Drag Embedment	None	n/a		1	70	70
Vertical Load	None	n/a		1	70	70
Suction Bucket	Boulder removal	100		1	760	760
Drilled / Screw Piles	None	n/a		1	280	280
Driven / Impact Piles	None	n/a		1	760	760

5.7.5 Dynamic Inter-array Cables

Installation of the inter-array cables will most likely take place once the floating substructures and WTGs have been installed. Installation of the inter-array cables may occur before the floating substructures. In this scenario, the cables would be wet stored on the seabed and marked appropriately following consultation with MCA and Northern Lighthouse Board (NLB). A typical sequence for the installation of the inter-array cabling (also relevant for export cabling) is as follows.

Pre-lay surveys (using ROV and potentially MBES) of proposed cable corridors will be undertaken to identify any requirement for obstacle removal; due to the site conditions, these are likely to be just prior to installation. If required, identified obstacles and/or boulders will be removed along the proposed cable route (for the section of dynamic cabling laid on the seabed). This would be achieved by a pre-lay grapnel run (2-m wide along the length of the cable route) to hook any linear debris; if any debris is hooked, it will be recovered to the vessel for onwards disposal / recycling ashore. Areas of boulders and confirmed UXO may also require clearance if not avoidable by a minor cable route deviation.

Boulders would be removed by either a boulder clearance plough or a grab unit lowered from a construction vessel, with the boulders being moved onto the seabed adjacent to the cable route. It is assumed that it will be possible to avoid any UXO encountered. Should any further mitigation be required, such as clearance or detonation, this would be subject to separate assessment and licence applications.

Seabed preparation may be required to level the seabed for the burial techniques to be employed effectively. In the worst case scenario, 100% of the inter-array cable route (seabed laid proportion) may require some form of seabed preparation and/or boulder removal. This equates to a maximum seabed footprint of 200,000 m^2. However, the extent of what is required will only be fully understood when the final WTG layout is confirmed, and the geophysical information is analysed against this layout.

The cable installation vessel moves to the site of the pre-installed floating structure where the cable is pulled into the floating structure and secured. The cable (with buoyancy modules) is then deployed into the water column. The second end of the cable is then deployed and pulled and secured into another floating structure (Figure 5.13).

Different approaches and techniques are available for installation of the inter-array cables laid on the seabed and these are:

> Pre-lay trenching using a displacement plough to create a pre-lay trench which the cable is then installed into. A separate backfill plough may then be used to push the spoil heaps created by trenching over the cable, thus creating the required cable cover;

> Post-lay trenching using a variety of tools including:

  - Jet trenchers (either self-propelled or mounted as skids onto ROVs) which inject water at high pressure into the sediment surrounding the cable. The seabed is temporarily fluidised and the cable is lowered to the required depth. Displaced material is suspended in the water and then resettles over the cable. This process is controlled, to ensure that sediment is not displaced too far from the cable;
  - Mechanical trenchers which bury the cable by lifting the laid cable whilst excavating a trench below, and then replacing the cable at the base of the trench and allowing the soil to naturally backfill behind the trencher;
  - Non-displacement ploughs which simultaneously lift a share of seabed whilst depressing the cable into the bottom of the trench. As the plough progresses, the share of the seabed is replaced on top of the cable; and

> Simultaneous cable lay and burial, using a jet trencher or non-displacement plough.

A combination of the above methods may be used for inter-array cable installation, depending on the ground conditions.

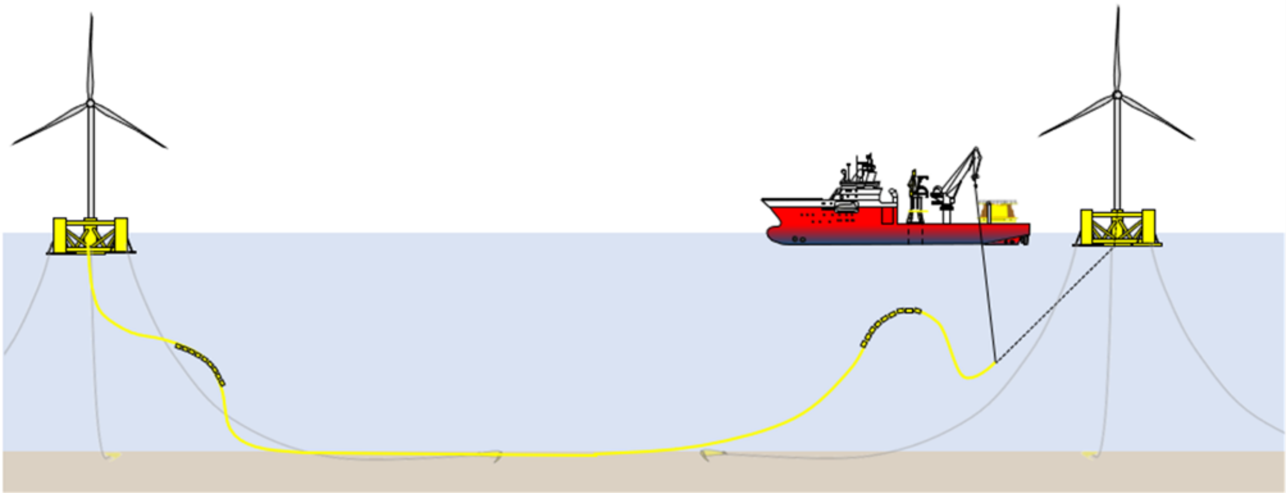


Figure 5.13 Inter-array cable installation (including catenary mooring for illustrative purposes)

5.7.5.1 Inter-array cable seabed preparation and protection

Cables which have not been adequately protected by burial generally need some form of remedial protection to reduce the risk of damage to the cable. Immediately following installation, post-installation surveys will be conducted to confirm target burial depths have been achieved and identify where remedial protection measures (e.g. rock placement, concrete mattresses, matts, or sand-grout bags) will be required. Cable protection, either by burial or placing of external protection over the cables, will take place after cable laying. Typical cable protection solutions are the same as those presented in Section 5.7.4.2.

For the inter-array cables, the target would be to ensure 100% burial of the inter-array cables on the seabed. However, as a worst case scenario, it is estimated that up to 50% of the cabling that is on the seabed may require additional remedial cable protection in the form of rock placement, concrete mattresses, matts or sand-grout bags. It should be noted that this is a worst case estimate and during detailed design the requirement for cable protection will be reviewed, to reduce cable protection volumes where possible. The maximum width of cable protection along the cable route will be 7 m, which equates to a worst case maximum seabed footprint of 70,000 m^2 of additional cable protection, though notably, this would be fully within the area of seabed already disturbed by the cable installation activities. The height above the seabed that this protection may protrude is approximately 1 m.

Once the required cable protection has been added, the cable is then commissioned, ensuring cable integrity is maintained during installation. The process is then repeated for all the WTGs in the array. Table 5.16 summarises the worst case parameters for the inter-array cables seabed preparation and protection.

Table 5.16 Inter-array cable seabed preparation and protection parameters

Seabed Preparation Required			Cable Protection Required				
Type	% of cable route requiring preparation	Max seabed footprint (m^2)	Type	% Of static cable requiring protection (on seabed)	Height of cable protection above seabed (m)	Width of cable protection (m)	Maximum seabed footprint of cable protection (m^2)
Boulder Clearance Seabed Levelling	100%	300,000	Rock placement / concrete mattresses / matts / sand-grout bags	50	1	7	70,000

5.7.6 Offshore Export Cable(s)

Following onshore readiness, a typical export cable installation will begin with pre-construction surveys, followed by debris clearance and seabed preparation along the full route(s) of the offshore export cable(s). The SHE Transmission Orkney-Caithness Project is within the OECC and therefore there is potential for interaction during construction at the landfall location as both projects make landfall at Dounreay. This project is consented but is currently on hold subject to the approval of a needs case by Ofgem concerning the viability of new generation projects on Orkney. Potential interactions with this infrastructure are considered and assessed in Chapter 18: Other Sea Users of the Marine Environment. Additionally, a radiation risk assessment of the seabed sediments across the Offshore Development and particularly within the Dounreay Food and Environment Protection Act (FEPA) closure zone (a 2-km area of water around the main outfall pipe of the Dounreay Nuclear Facility) has been undertaken by Nuvia (Nuvia, 2021); this concluded that the risk of disturbing radioactive particles during offshore installation operations is low, including cable lay and HDD operations within the FEPA zone.

A typical export cable installation approach is as follows – the onshore end of the cable is connected to the onshore winch wire through the pre-installed HDD borehole (see Section 5.7.7) and pulled to the transition joint bay. Once secured, the installation vessel will move along the cable route paying out the offshore export cable to the seabed or trench, ensuring cable integrity is maintained. The in-field end of the cable is installed onto the floating structure in line with the steps outlined for the dynamic cable in Section 5.7.5. The exact installation sequence and lay direction can differ depending on in-field conditions and the final offshore export cable design adopted. As with the inter-array cables, there is a potential that the dynamic section of offshore export cable would be wet stored on the seabed, prior to the installation of floating substructures. In this situation, the cable would be marked appropriately following consultation with MCA and NLB.

If a second offshore export cable is required as part of the Offshore Development, the cable will be laid in a separate trench with a minimum separation distance of 20 m between the two cable trenches. Commissioning will then take place, and lastly installation of cable protection systems (as detailed below) where necessary.

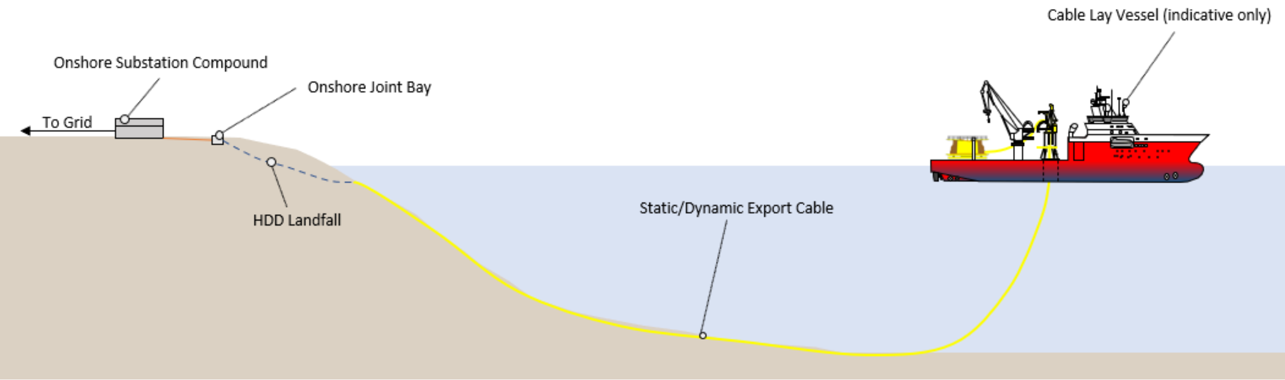


Figure 5.14 Offshore export cable installation

5.7.6.1 Offshore export cable seabed preparation and protection

Prelay works will be similar to those described in Section 5.7.5 for the inter-array cables. In the worst case scenario, 100% of the offshore export cable(s) route (seabed laid proportion) may require seabed preparation in the form of seabed levelling, pre-cut trenching and/or boulder removal. This equates to a maximum seabed footprint of 375,000 m^2 if both offshore export cables are required. However, the extent of what is required will only be fully understood when the final WTG layout and offshore export cable route are confirmed and the geophysical information analysed against this layout and route. Similarly, the method used for installing and trenching the offshore export cable(s) will be determined during detailed design but will be one or more of the techniques described for the inter-array cables (Section 5.7.5).

For the offshore export cable(s), the target will be to achieve burial for 100% of the offshore export cable. However, in a worst case scenario where it is not possible to achieve the minimum target trench depth of 0.6 m, up to 50% of the offshore export cable(s) route may require additional cable protection measures similar to the inter-array cables. Typical cable protection solutions are the same as those presented in Section 5.7.4.2.

It should be noted that this is a worst case estimate and during detailed design the requirement for cable protection will be reviewed, to reduce cable protection volumes where possible. The maximum width of cable protection along the cable route will be 7 m, which equates to a worst case maximum seabed footprint of 87,500 m^2 of additional cable protection required. However, as with the inter-array cabling, this would be fully within the area of seabed already disturbed by the cable installation activities. The maximum height above the seabed that the cable protection may protrude is approximately 1 m. Table 5.17 summarises the worst case parameters for the offshore export cable(s) seabed preparation and protection.

Table 5.17 Offshore export cable seabed preparation and protection parameters

Seabed Preparation Required			Cable Protection Required				
Type	% of cable routes requiring preparation	Max seabed footprint (m^2)	Type	% Of cable requiring protection (on seabed)	Height of cable protection above seabed (m)	Width of cable protection (m)	Maximum seabed footprint of cable protection (m^2)
Boulder Clearance and Seabed Levelling / Pre-cut Trenching	100%	375,000	Rock placement / concrete mattresses/ matts / sand-grout bags / rock bags	50	1	7	87,500

5.7.7 Offshore Export Cable Landfall

The landfall is an interface area between the offshore and onshore elements of the offshore wind farm. The construction work will typically involve both offshore elements and onshore elements.

On review of the ground conditions, HWL has determined that one of the landfall options presented in the Scoping Report, that of pinning the cable to the disused Dounreay cooling water intake, at Dounreay Nuclear Facility, is not technically feasible so this option has been removed from the Design Envelope of the Offshore Development. Therefore, HDD is the design solution taken forward by the Offshore Development in respect of landfall installation. The landfall location will be situated in an area between the boundary of the Vulcan Naval Reactor Test Establishment and the White Geos (adjacent to Sandside Bay), as shown in Figure 5.15. The exact location of the landfall within this area for landing the cables will be established following a detailed investigation of environmental and technical factors.

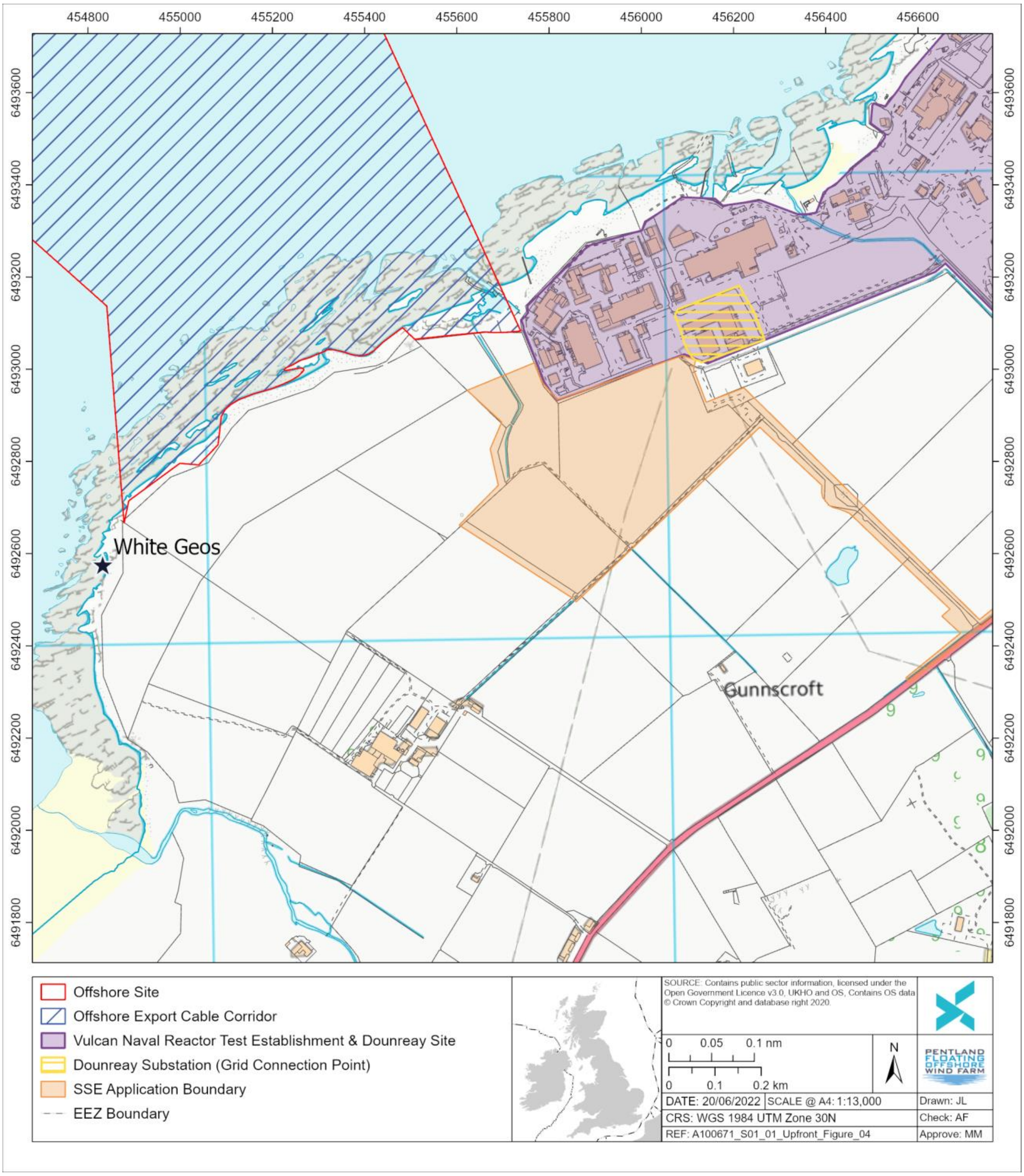


Figure 5.15 Offshore export cable landfall location

HDD involves drilling of small pilot hole(s) from the landward side to an exit point below MLWS. The HDD exit point is expected to be approximately 600 m offshore but may vary between 400 m to 700 m and the exact location is to be confirmed from further engineering studies. The water depth range in this region is from 15 m to 40 m. Up to two ducts will be required to accommodate up to two offshore export cables and this may require up to five bore attempts. In the event that a bore fails, it would be abandoned and backfilled.

During HDD, the hole(s) is widened to accommodate a conduit pipe through which the cable is pulled. For the base case cable, the outer diameter (OD) will be approximately 180 mm and the duct size is likely to be around 500 mm OD, to provide an internal diameter between 1.5 and 2.5 times the cable diameter. The size of the final HDD bore diameter would be approximately 750 mm with a maximum HDD bore diameter of 750 mm per drilled hole. Once installed, the cable is fed into a cable joint transmission bay.

HDD requires a temporary landward working area (typically called an HDD compound) of up to 5,600 m^2 for both cables during construction to accommodate the drilling equipment and ancillary plant. The HDD compound, which contains the cable joint transmission bay, will be above MHWS and is therefore included within the PFOWF Onshore Consent. The drilling compound would be set back approximately 150 m from the edge of the cliffs which should provide sufficient space for the arced drill profile to pass beneath the cliffs and exit onto the seabed below MLWS.

The exact location of the landfall for landing the cables will be established following a detailed investigation of environmental and technical factors. The following general HDD procedure will be followed:

- The existing access track (onshore) is temporarily extended (length will be dependent on the final landfall location);
- The HDD compound (onshore) is established;
- An onshore drill rig begins drilling a small diameter pilot hole from the HDD compound, beneath the intertidal area, to a point offshore (below MLWS) where the offshore cable laying vessel can gain safe access;
- As this hole is drilled, a ‘drilling mud’ (typically Bentonite, an inert material consisting of a mixture of water and natural clays) will be injected into the hole behind the drilling head to ensure it is kept stable and to flush out drill arisings. Once the drilling head reaches the exit point offshore and punches through the seabed, a small quantity of this drilling mud and cuttings will be discharged to the marine environment. Best practice mitigation will be implemented to minimise the amount of drill mud / cuttings released, including the pilot hole stopping short of the exit point prior to reaming and a flushing and cleaning run being undertaken prior to pop-out;
- A steel reamer is then pulled back from an offshore vessel (AHTS vessel or similar) through the pilot hole enlarging the diameter of the hole as it progresses. Several reaming operations may be necessary to achieve a size suitable for accommodating the cable duct;
- The exact depth of the drilling depends on the soil profile and geology, however, a drill depth of between 5 m to 20 m below ground level is typical;
- The cable duct is typically pushed through the hole from the landward side (although in some instances it may be possible to pull the duct through the hole toward the HDD compound onshore). A short section of the offshore duct end may be capped and temporarily protected until offshore export cable(s) installation commences;
- Shortly before offshore export cable(s) installation commences, ducts will be prepared for pull-in operations, including being cut back to their design length, and the attachment of a bell mouth. Note this will typically require a diver support vessel, with a mooring system;
- Once the offshore cable has been installed, the duct may be injected with a thermal dissipation medium (typically a thermal grout) to ensure that the cable does not overheat, although the need for any thermal grout will be confirmed once the geology is known;

> The HDD compound is removed, and the site restored in accordance with any onshore consent conditions and to the Landowner's satisfaction; and

> The temporary access track is removed in accordance with any onshore consent conditions and to the Landowner's satisfaction.

The worst case design parameters for the HDD activities are presented in Table 5.18.

Table 5.18 Design parameters for HDD activities

Parameter	Value / Description
Landfall location	HDD will occur between the boundary of the Vulcan NRTE and the White Geos (adjacent to Sandside Bay).
Number of drilled holes	Two successful drilled holes (up to five attempts)
Offshore HDD length	Up to 700 m
Hole bore diameter	750 mm
Volume of drilling mud lost to sea at breakthrough of exit point	264 m^3 per borehole (based on initial estimates, to be confirmed during detailed design)

5.8 Construction Schedule

A detailed construction programme will be developed as design and procurement activities progress. The offsite fabrication activities for the Offshore Development are planned to commence upon financial close, anticipated in Q4 2024, and will continue for approximately 18 months.

The offshore construction activities are anticipated to commence in 2024 with the commencement of the HDD works at landfall. The installation of the offshore components is then likely to be completed across two seven-month construction stages, anticipated to commence in spring 2025 (Stage 1), pausing over the winter months and then continuing in spring and summer 2026 (Stage 2).

It is proposed that anchor installation and offshore export cable(s) installation would take place in Stage 1 of the construction phase (anticipated 2025) with the remaining offshore components installed in Stage 2 (anticipated 2026). Should there be any delays in the installation programme for HDD works or anchor installation, due to weather or other unforeseen circumstances, offshore export cable installation may be delayed to Stage 2. It should be noted that installation of the offshore export cable(s) will take place over one season only, in either Stage 1 or Stage 2, but not both.

In terms of construction sequencing, it is proposed that a single WTG and associated floating foundation will be installed in Stage 1, ahead of the remaining WTGs which will be installed in Stage 2. Whilst this approach will be confirmed during detailed design, the installation of a single WTG will provide a valuable opportunity to trial the technology required for the array.

Should consent be granted, full details of the construction programme, construction sequencing and installation methodologies for the Offshore Development will be confirmed within the Construction Programme consent plan and Construction Method Statement for the Offshore Development, and this will be submitted to Marine Scotland-Licensing Operations Team (MS-LOT) for approval on behalf of Scottish Ministers.

The full array is anticipated to be commissioned and operational by the end of Q4 2026.

The nature of offshore work requires operations to be planned on a 24-hour, seven days a week basis; however, work will not be continuous over the whole construction period. The durations presented are indicative only and are subject to change which may arise, for example, from weather downtime, site conditions, equipment lead times and supply programmes, sequential work requirements, and logistical issues.

The key construction activities and anticipated high-level durations are outlined in Figure 5.16. It should be noted that these are anticipated construction years only and the construction programme may change; The final construction programme for the Offshore Development will be confirmed in the Construction Programme which will be required as a condition of the S.36 consent.

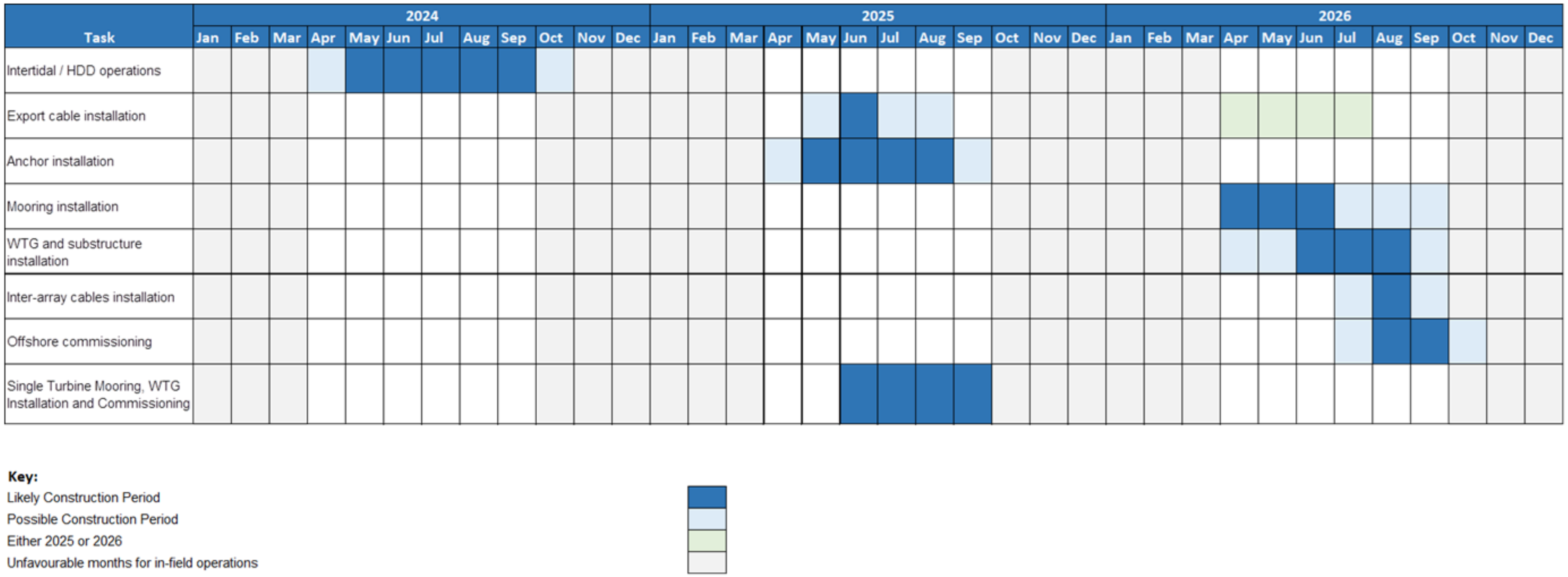


Figure 5.16 Indicative high-level programme for the Offshore Development (note that this is subject to change and will be confirmed in the Construction Programme)

HWL will endeavour to minimise any impacts or disruption to other users of the sea in planning the construction activities. For example, the offshore export cable(s) will be buried or protected as soon as is practicable after being laid on the seabed. It is proposed to maintain an ongoing dialogue with the commercial fishing sector from project inception, throughout development and into construction and operation through the designated communication channels, including the Fisheries Liaison Officer.

5.9 Construction Vessels

Offshore construction will require a variety of different vessel options depending on the final anchor, mooring and substructure solutions selected, as well as the chosen assembly port and construction strategy taken. Where vessels require anchoring, they will be accompanied by anchor handling vessels.

It is expected that the main types of vessels that may be used will include:

- Construction Support Vessel: Needed for installation of most anchor and mooring solutions;
- AHTS vessel: Needed for installation of most anchor and mooring solutions;
- DP floating Heavy Lift Vessel: Possibly needed for installation of gravity base anchors;
- Pre-installation seabed clearance vessel;
- Cable Lay Vessel: This will be a DP vessel utilised for inter-array and offshore export cable(s) installation. A dive support vessel may be required for cable pull in preparation. This may require the installation of a temporary mooring system;
- Rock placement vessel;
- ROV;
- Crew transfer vessels (CTV);
- Guard vessel(s); and
- Survey vessel(s).

As there are a number of design options under consideration for the Offshore Development, there are multiple scenarios for the numbers and type of construction vessels that may be used, however, it is likely that at different stages of the installation operations there will be a combination of the above vessels working onsite at any one time.

Some vessels will likely come from outside United Kingdome (UK) waters; in this instance, standard measures for mitigating the risk of Invasive Non-Native Species, and all vessels will comply with the International Maritime Organisation (IMO) Ballast Water Management Convention.

To inform the EIA process, conservative assumptions have been made on the vessel activity involved in the offshore installation campaign; these are presented in Table 5.19.

Table 5.19 Estimated vessel requirements during the offshore installation campaign

Vessel Requirement	Total Number
Number of vessels used throughout the campaign	30
Number of vessels on site simultaneously	10
Number of vessel movements (defined as a return entry-exit from the Offshore Site) that may be required	660

5.10 Offshore Operation and Maintenance

5.10.1 WTGs and Floating Substructures

The overall in-service inspection, maintenance, and monitoring of the WTGs will be carried out in accordance with the service requirements provided by the WTG manufacturer. This will to a large extent follow normal seabed fixed WTGs, however, on a few central elements there will be a significant difference. Mainly related to major component replacements and below-water inspections.

The accessibility criteria for the floating substructures are expected to be the same as that of fixed-bottom installations. However, the Offshore Site is located in extreme conditions, which may limit access to WTGs. The primary means of access during summer will be from CTVs pushing onto the boat landing on the floating structure. A hoist operation from a helicopter to the WTG will be the primary means of access during bad weather and over the winter months. The specific access system / technique will be confirmed during the FEED and detailed design phases.

It is expected that the floating substructures will be painted in a low-toxicity anti-fouling paint and will also be fitted with cathodic (anode) protection to reduce the risk of corrosion of the steel structures. The exact corrosion protection measures to be employed will be developed during detailed design and will be provided to MS-LOT post-consent in accordance with consent conditions as required. The substructures will be designed to accommodate marine growth; however, growth levels will be inspected regularly, and subsequent removal of this growth will be undertaken using water jetting tools (or other suitable means) if substantial accumulation is in evidence.

For repairs that cannot reasonably be completed onsite, towing to port or shallower water where a jackup vessel can be used for repair, may be required. The floating substructure, mooring, and inter-array and offshore export cable arrangements will be designed to enable the safe and efficient disconnection of the structure from its moored position. The structure will also be designed to allow for towing with conventional tugs between the Offshore Site and port. The following sequence is envisaged for a major component changeout:

- The WTG is shut down and is isolated from the inter-array cable;
- The power cable is disconnected from the WTG and the cable end is suitably wet stored;
- The mooring system is disconnected from the WTG, with the moorings laid safely on the seabed;
- The complete WTG and structure assembly is towed to the operations and maintenance port / shallow waters for repair; and
- Following quayside repair, a repeat of the relevant steps of the installation sequence will be completed to bring the WTG back into operation.

5.10.1.1 Operational WTG noise

An assessment of the operational WTG noise including that of cumulative noise anticipated from the Offshore Development is presented in Offshore EIAR (Volume 3): Appendix 5.1: Operational Turbine Noise.

Within the assessment, predicted operational noise levels have been compared to noise limits derived in accordance with the ETSU R 97 guidelines, either based on the simplified assessment method described therein, or those determined for the other wind farm sites considered (at relevant receptors). These predictions were made based on conservative (worst case) estimates of emission levels for WTGs of the type and size which would be installed for the Offshore Development.

The outcomes of the assessment demonstrate that the WTGs would operate within the limits derived at onshore locations and that the cumulative impact on receptors in proximity to the other wind farm sites considered would be negligible.

The assessment, therefore, concludes that operational noise levels from the Offshore Development will be within levels recommended in national guidance for wind energy schemes.

5.10.2 Moorings and Anchors

Depending on the material used for the selected mooring option, protection from corrosion will be provided by cathodic (anodes) protection for steel moorings or polyurethane protection cover for synthetic moorings. Any section of the mooring lines that rest on the seabed will not be protected in these ways as the lines will be in constant movement against the seabed.

The mooring monitoring, inspection and maintenance will be in line with expectations laid out by the Health and Safety Executive and MCA for floating wind (HSE / MCA, 2017). The overall operation and maintenance strategy will be developed post-consent; however, it is anticipated that the inspections will follow the inspection scheme stipulated by the mooring line original equipment manufacturer. Later, a risk-based approach might be adopted. The inspections will be undertaken via conventional periodic visual (ROV) inspections. Inspections would be undertaken to check the following:

- Anchor condition (specific inspection informed by selected technology) for evidence of displacement and scour;
- Mooring line condition, including corrosion (particularly at the point of touch down on the seabed), amongst other technology-specific considerations;
- Connection points for wear, corrosion, and functionality (i.e. free rotation in case of swivel connector);
- Marine growth levels, and subsequent removal of this using water jetting tools, if substantial accumulation is in evidence; and
- Collection and removal of debris (such as abandoned fishing nets, pots, and other marine rubbish) amongst the mooring lines.

The Carbon Trust Phase 1 Floating Wind Joint Industry Project Summary Report (Carbon Trust, 2018) identified an industry-wide need for innovation in the areas of floating wind moorings. As such the Offshore Development needs to maintain flexibility to capitalise on innovations in this area such as sensor technologies and autonomous underwater vehicles amongst other unforeseeable technological advances.

5.10.3 Dynamic Inter-array and Offshore Export Cables

During the life-cycle of the Offshore Development, there should be no need for scheduled repair or replacement of the subsea cables; however, reactive or proactive repairs may be required. Periodic ROV inspection surveys will be performed to ensure the cables remain buried and undamaged. If cables do become exposed, re-burial works, or remedial cable protection works would be undertaken. Maintenance activities expected to take place on the cables during the operational phase include but are not limited to:

- Cable route inspection, both seabed and water column;
- Cable repair by recovering the cable from its trench / water column and making the necessary repairs (i.e. splicing in a new section etc.);
- Reburial of sections of cable which have become exposed;
- Remedial protection over sections of the cable identified as in need of protection; and
- Periodical removal of marine growth from the submarine cable and relevant accessories

5.10.4 Operation and Maintenance Vessels

Operation and maintenance activities can be categorised into two main types: planned / preventative and unplanned / corrective maintenance.

Planned maintenance is according to scheduled services and includes general inspection and servicing, oil sampling / change, cleaning of equipment, investigation of faults, minor fault rectification, as well as replacement of consumables. These types of maintenance activities will generally take place during the summer months.

Unplanned maintenance covers fault rectification, unexpected minor repairs and major component replacements / repairs. As these can't be foreseen, they may take place at any time of the year across the Offshore Development's life-cycle and may require urgent intervention to rectify any critical issues as quickly as possible. Outside the summer period, the minor repairs will be predominantly supported by helicopter. If tow-to-port / shore is needed, it will likely be pushed to the summer period to find suitable weather conditions unless a suitable weather window is identified.

Operation and maintenance activities are expected to be coordinated from an onshore harbour base located in close proximity to the Offshore Development. A variety of types of vessels are likely to be required depending on the type of maintenance that is required; the most likely vessels for routine planned maintenance will be those vessels listed below, however, for unplanned repairs, there may be a requirement for different and/or larger vessels:

- CTV;
- ROVs; and
- Survey vessel(s).

5.11 Decommissioning

5.11.1 Decommissioning Approach

Under Section 105 of the Energy Act 2004 (as amended) (UK Parliament, 2004), developers of offshore renewable energy projects are required to prepare a Decommissioning Programme for approval by Scottish Ministers. A Section 105 notice is issued to developers by the regulator after consent has been issued for the given development. Developers are then required to submit a detailed plan for the decommissioning works, including anticipated costs and financial securities; this is then consulted on by MS-LOT prior to seeking ministerial approval.

The overarching principles that will be followed when developing an appropriate Decommissioning Programme are derived from the Department of Business, Energy and Industrial Strategy (BEIS) Guidance Note (2019) (BEIS, 2019) and Marine Scotland's Draft Guidance Note (2019) (Scottish Government, 2019), and will consider:

- The Best Practicable Environmental Option, which is the option that delivers the most benefit or least damage to the environment at an acceptable cost, both in the short and long term. This involves balancing the reduction in environmental risk with practicability and the cost of reducing the risk:
- Safety of surface and subsurface navigation;
- Other uses of the sea; and
- Health and safety considerations.

In addition, the Offshore Development will adhere to the principles of:

- Sustainable development, and will seek to ensure that, as far as reasonably practicable, future generations do not suffer from a diminished environment, or from a compromised ability to make use of marine resources; and
- Polluter pays principle, which acknowledges the Project's responsibility to incur the costs associated with its impact on the environment.

In developing a Decommissioning Programme, HWL will seek to maximise the re-use of materials and will pay full regard to the 'waste-hierarchy'. To ensure that commercial viability is maintained, the Best Available Technique Not Entailing Excessive Cost decommissioning solutions will be sought. In achieving the above objectives, the Offshore Development will ensure practical integrity. When decommissioning the Offshore Development, HWL will seek to minimise the influence on land transportation and where practicable, will plan transportation between the coast and respective waste management facilities to reduce safety issues and disturbance to traffic.

In line with the Scottish Government's default position for the decommissioning of Offshore Renewable Energy Installations (OREI), the starting presumption is that at the end of the Offshore Development's operation and maintenance phase, there will be a requirement for all offshore components (above and below seabed) to be completely removed to shore for re-use, recycling, incineration with energy recovery, or disposal at a licensed site. As the Offshore Development's anticipated lifetime is up to 30 years from full commissioning, there may have been advances in technological capabilities for decommissioning and/or changes to legislation by this time, therefore decommissioning best practices and legislation will be applied at that time of the Offshore Development's decommissioning. Under international standards such as those published by the IMO, there is the potential to consider leaving components *in situ*, however, it is understood that this would require a robust and compelling justification to be presented to Marine Scotland to be granted approval for partial removal of the Offshore Development. In this instance, a comparative assessment would be undertaken to provide a recommendation, based on the performance against five main criteria: Safety, Environmental, Societal, Technical Feasibility and Economic.

Throughout the Offshore Development's life-cycle, the Decommissioning Programme will be reviewed and updated every five years. Consultee bodies listed in the S105 Notices, and any additional consultees identified by MS-LOT or HWL, will be provided with the opportunity to comment on the final decommissioning strategy prior to it being finalised. It is anticipated that the final revision process will commence two years prior to the initiation of decommissioning activities.

5.11.2 Decommissioning the WTGs and Floating Substructures

The removal of WTG components, including blades, nacelle, and tower, will largely be a reversal of the installation process and will likely be undertaken following repositioning to shore. The general methodology for carrying out WTG decommissioning will be:

- De-energise WTGs and isolate them from the grid;
- Disconnect the dynamic cables and recover or lay down for later recovery; and
- Disconnect the floating foundations from their moorings and tow complete foundation with WTG to port / onshore facility for dismantling and processing; and

Once onshore, the components are likely to be processed as follows:

- All hazardous substances and fluids will be removed from the WTGs (such as oil reservoirs and any hazardous materials and components). All such materials will then be disposed of in accordance with relevant regulations at the time of disposal;
- All steel components and any other salvageable components will be sold for scrap to be recycled. This forms the bulk of the WTG structures;
- Electrical components will be disassembled and handled in accordance with the newest International Electrotechnical Commission 61400 at the time of decommissioning; and
- The WTG blades (fibreglass) will be disposed of in accordance with the relevant regulations in force at the time of decommissioning.

5.11.3 Decommissioning the Anchoring Systems

The removal and dismantling of the anchoring systems will largely be a reversal of the installation process and subject to the same constraints. However, for piles that have been driven or screwed into the seabed to significant depth, the proposed decommissioning approach would be to cut off the piles below seabed level and recovered to the surface for onshore disposal. Currently, abrasive water jetting internally within the piles is considered likely to be the preferred method for the decommissioning of the piles, but other methods may be preferred at the time of decommissioning. The decision to leave piles *in situ* would be agreed upon through consultation and assessment, to ensure this was the most suitable approach; any application for this would be supported by a comparative assessment process and a suitable body of evidence.

Decommissioning will be undertaken in the same controlled manner as the installation process and in accordance with a risk management plan, to ensure the same level of safety and pollution control measures. Whichever anchoring system is deployed, the post-decommissioning state will be the same in terms of leaving the site with a clear seabed surface, free from obstruction to other seabed traffic such as fishing gear. Components will be re-used or recycled, wherever possible.

5.11.4 Decommissioning the Offshore Export and Inter-array Cables

It is anticipated that full removal of both the dynamic and seabed laid static cables (buried and protected) will be required unless there is compelling evidence to leave the buried sections *in situ*. The sequence for removal of the cable is anticipated to be:

- Locate the cable using a grapnel and lift it from the water column or seabed. Alternatively, or in addition, it may be necessary to use an ROV to cut and/or attach a lifting attachment to the cable so that it can be recovered to the vessel;
- For dynamic cable removal the buoyancy modules along with all other associated accessories will be removed as the cable is recovered to deck;
- Seabed material may need to be removed to locate the cable (excluding dynamic cables). This is likely to be carried out using a water jetting tool similar to that used during cable installation;
- The recovery vessel will either 'peel out' the cable as it moves backwards along the cable route whilst picking it up on the winch or cable engines, or, if the seabed is very stiff / hard, it may first under-run the cable with a suspended sheave block to lift the cable from the seabed. The use of a suspended sheave block may be carried out by a separate vessel, such as a tug, prior to the recovery vessel ‘peeling out’ the cable;
- The recovery vessel will either spool the recovered cable into a carousel or cut into lengths as it is brought aboard before transport to shore; and
- The cables will be recycled onshore.

If through consultation and assessment, a decision to decommission some of the seabed-laid cables *in situ* was deemed the most suitable approach, any application for this would be supported by a comparative assessment process (in line with BEIS guidance) and a suitable body of evidence. If approval was granted to leave buried cables *in situ*, the ends of the cables will be cut as close to the seabed as possible. The ends will be weighted down and buried (probably using an ROV) to ensure they do not interfere with trawling and other rights and needs of legitimate users of the sea.

5.11.5 Removal of Scour or Cable Protection

It may be preferable to leave the scour or cable remedial protection *in situ* to preserve any marine habitat that may have developed over the life of the Offshore Development; this is particularly the case for rock placement / boulders as these are generally quite small in grade size and thousands in quantity so not practical to recover. Relevant stakeholders and regulators will be consulted to establish the most appropriate approach. If removal is deemed necessary, the removal sequence is anticipated to be:

- Concrete mattresses are likely to be recovered using a grab vessel, and transferred to a suitable barge for transport to an approved onshore site for appropriate re-use or disposal; or
- The filter layer is likely to be dredged and transported to be re-used or disposed of at a licensed disposal area (this could be offshore or onshore).

5.11.6 Seabed Clearance and Restoration of the Offshore Site

HWL is committed to restoring the Offshore Site, as far as is reasonably practicable, to the condition that it was in prior to construction of the Offshore Development. In line with the details provided above, HWL is also committed to ensuring the Offshore Development is safely and effectively decommissioned.

5.11.7 Post-Decommissioning Monitoring, Maintenance, and Management of the Site

Should any infrastructure be decommissioned *in situ*, some post-decommissioning activities may be required to identify and mitigate any unexpected risks to navigation or other users of the sea. This includes, for example, anchor piles or cables becoming exposed through natural sediment movement. The requirement for monitoring and the extent and approach taken will be determined based on the scale of the remaining infrastructure, the risk of exposure and the risk to marine users. The requirement will be agreed upon with MS-LOT in subsequent revisions of the Decommissioning Programme as the development of the Offshore Development progresses.

Where considered necessary, post-decommissioning monitoring surveys of the seabed will be carried out following the completion of the decommissioning works. Surveys are expected to comprise geophysical surveys (such as swathe bathymetry, side scan sonar, and magnetometer). Surveys will be undertaken in line with the final Decommissioning Programme, and in line with the survey scopes consulted on with MS-LOT and relevant stakeholders. Compliance will be verified through an independent third-party survey upon completion of the works. The results of these surveys will be issued to MS-LOT for record-keeping purposes. Any post-decommissioning hydrographic surveys will be undertaken in accordance with the requirements set out in the relevant guidance in place at the time.

If an obstruction appears above the seabed following decommissioning which is attributable to the Offshore Development, it will be marked so as not to present a hazard to other sea users and remediated if required. Any remediation method will be agreed upon with MS-LOT. The navigational marking will remain in place until the obstruction is removed or no longer considered a hazard due to suitable remediation. The monitoring of the obstruction will be built into any monitoring and maintenance programme.

Details of the post-decommissioning monitoring, maintenance, and management will be discussed with stakeholders close to the point of decommissioning and will consider relevant guidelines and industry standard good practice at the time and where possible this will take the form of non-intrusive survey techniques.

5.12 Safety Zones, Marking, and Lighting

5.12.1 Construction (and Decommissioning)

In accordance with the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007 (UK Parliament, 2007), it is expected that a 500-m safety zone around each renewable energy installation will be applied for under Section 95 of the Energy Act 2004 (UK Parliament, 2004) during the period of construction (and decommissioning) works whilst restricted in ability to manoeuvre vessels are present. Additionally, during the period of construction (and decommissioning), it is expected that a 50-m ‘pre-commissioning’ safety zone will be applied for around each renewable energy installation. Section 62 of the Scotland Act 2016 (Scottish Parliament, 2016) amends Section 95 of the Energy Act 2004 making Scottish Ministers the appropriate Minister for safety zones. To minimise disruption to navigation by users of the sea, safety zones are expected to be established around areas that have relevant activities taking place at a given time. As such, the establishment of safety zones is expected to be phased throughout the PFOWF Array Area as construction work is undertaken. The exact locations will be subject to detailed engineering, informing the construction plan, and will be determined prior to the commencement of construction.

Legal safety zones can only be established around the outer edge at sea level of an OREI, rather than a vessel. Nevertheless, it is a standard safe working practice to establish advisory minimum safe passing distances around areas of vessel activity that present a navigational safety risk to marine users. This includes providing information of planned works and a requested safe clearance distance. These advisory safety zones are generally 500 m and move with the vessel during its operation.

Within port limits, the relevant Harbour Authority may also choose to establish safety or exclusion zones around works, should a navigational safety risk be presented, for example, due to the proximity to navigational channels or volume of traffic. This will be discussed with the relevant Harbour Authority during the works planning process. Safety zones, and/or any other exclusions required, will be implemented and communicated through standard protocol (e.g. Notice to Mariners).

5.12.2 Operation and Maintenance

The Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007 (UK Parliament, 2007) provides the regulatory framework for establishing safety zones to OREIs in the UK, and states that 50-m safety zones may be applicable during wind farm operation. However, as MGN 654 advises, if offshore wind developers wish to submit an application for an operational safety zone, it must be accompanied by a robust safety case and supporting evidence, providing justification for the safety zone(s) and how it will be managed.

Standard practice for fixed-bottom wind farms in the UK to date has been that operational safety zones are not required. As the Offshore Development is a floating wind farm, HWL are currently assessing whether an operational safety zone(s) is needed for the Offshore Development and whether these should be statutory or advisory. The requirement for operational safety zones will be considered as part of the Project Safety Case on review of the mutual risks posed, post-construction, to the Wind Farm and third parties. This will be dependent on the outcomes of the detailed engineering phase as well as consultation with key stakeholders during the EIA process. If it is determined that a safety zone is needed around each of the WTG, it is considered that this would comprise a radius of 50 m measured from the outer edge of the floating substructure. Further consultation and risk-based justification will be carried out if the operational zones are planned to be statutory rather than advisory. This will include consideration of the fact that there will be an excursion zone around the structure (refer to Figure 5.10).

During periods of major maintenance works and where a risk is posed to marine users or wind farm technicians, further temporary 500-m zones may be applied for under the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007. This may be undertaken in conjunction with standard vessel safe operating procedures and the use of guard vessels as described in Section 5.12.1.

5.12.3 Colour Scheme, Markings, and Lighting

The Offshore Development will be designed and constructed to satisfy the safety requirements of the MCA as well as the marking, lighting, and fog-horn specifications of the Civil Aviation Authority, the NLB[ii] and the MCA. The use of AIS Aid to Navigation will be discussed with the NLB. Indicative information is provided below, however, the specific requirements for marking and lighting the Offshore Development will be determined post consent in consultation with the relevant stakeholders.

At present, whilst not a regulatory requirement it is industry best practice that the WTGs are marked with lights that are visible from 3 km (2 nautical miles) and from all angles during construction. It is intended that the site will be marked as a buoyed construction area with the buoy locations agreed upon with NLB.

When in operation, the platforms shall be painted yellow and marked with clearly visible unique identification characters, which will be visible from all sides and comply with applicable requirements in Maritime and Coastguard Agency MGN 654 (MCA, 2021). Currently, these recommend that they should be visible from at least 150 m from the structure and that lighting for this purpose is hooded or baffled to avoid unnecessary light

[ii] IALA R139 and G1162 are the active guidance and recommendations as of December 2021.

pollution or confusion with navigation marks. Additionally, for aviation purposes, the unique identification characters must be visible from the air and the WTGs shall have red blade tips and high contrast markings (dots or stripes) placed at 10-m intervals on both sides of the blades to provide helicopter pilots with a hover-reference point.

The colour scheme of the WTG tower, nacelle, and blades is likely to be light grey RAL 7035, white RAL 9010 or equivalent. However, as the Offshore Development is a test and demonstration project there has been some discussion with Marine Scotland and other consultees regarding the painting of the WTG blades. Should this be considered further it will be discussed with key consultees and dealt with post-consent. There is no anticipation that this configuration would lead to additional significant effects and if it is used will be dealt with through the DSLP; therefore, no variation to the consent would be required.

5.13 References

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