Mooir Vannin Offshore Wind Farm

Project Description

This document is part of a suite of preliminary environmental materials prepared to fulfil pre-applicc consultation requirements under The Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 (of Parliament) as applied to the Island by the Climate Change (Infrastructure Plar (Environmental Impact Assessment) (Application) Order 2024.

Revision Summary					
Rev	*Date*	*Prepared by*	*Checked by*	*Accepted by*	*Approved by*
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Glossary

Term	Definition
Applicant	Mooir Vannin Offshore Wind Farm Limited (Company Registration Number: 013051V)
Commitments	Commitments, or mitigation measures, are made by the Project to reduce and/ or eliminate the potential for likely significant effects (LSE) to arise as a result of the Proposed Development. Primary (Design) or Tertiary (Inherent) Commitments are both embedded within the assessment at the relevant point in the EIA (e.g., at Scoping, PEI or ES). Secondary commitments are incorporated to reduce LSE to environmentally acceptable levels following initial assessment so that residual effects are acceptable.
Decommissioning	The period during which a development and its associated processes are removed from active operation.
Environmental Impact Assessment (EIA)	A statutory process by which the environmental impacts of certain planned projects must be assessed before a formal decision to proceed can be made. It involves the collection and consideration of environmental information, which fulfils the assessment requirements of the EIA Directive including the publication of an Environmental Statement (ES).
Fibre Optic Cables	Fibre optic cables incorporated into the Electrical Cables that utilise a SCADA network to monitor and analyse operational performance, allows local and remote control of basic wind turbine functions and provides overall control of the transmission asset.
Intertidal	Area where the ocean meets the land between high and low tides.
Joint Bay (JB)	A joint bay provides a secure environment for the assembly of cable joints as well as bonding and earthing leads. A joint bay is installed between each length of cable.
Landfall	The location at the land-sea interface where the offshore export cable will come ashore.
Maintain	Includes inspect, upkeep, repair, adjust, and alter and further includes remove, reconstruct and replace, and "maintenance" must be construed accordingly.
Marine Infrastructure Consent	A consent granted by the Council of Ministers under the Marine Infrastructure Management Act 2016 (MIMA).
Maximum Design Scenario	The maximum design parameters of the combined project assets that result in the greatest potential for change in relation to each impact assessed.
Mitigation	Mitigation measures, or commitments, are commitments to reduce and/ or eliminate the potential for significant effects to

Term	Definition
	arise as a result of the Proposed Development. Mitigation measures can be embedded (i.e., part of the project design) or secondarily added to reduce impacts where potentially significant adverse effects are identified.
Mooir Vannin Offshore Wind Farm	Refers to "The Whole Project." All aspects of the Proposed Development, the terrestrial assets and an Operations and Maintenance base in the Isle of Man, and any associated UK Transmission Assets that are located outside the Isle of Man's jurisdiction.
Offshore Array	The generation (Wind Turbine Generators (WTGs) and Array Cables) and transmission (Interlink Cables, UK Transmission Assets and Offshore Platforms) asset infrastructure contained within the Agreement for Lease (AfL) area.
Offshore Converter Station (OCS)	Platforms located within the Offshore Array which house electrical equipment and control and instrumentation systems, used for converting the power to HVDC. They also provide access facilities for work boats and helicopters.
Offshore Electrical Connection Cable	The Electrical Cable(s) connecting the Offshore Array to landfall in the Isle of Man, including the Fibre Optic Cables from the turbines, to be located within the Offshore Electrical Connection Search Area.
Offshore Electrical Connection Search Area	The search area for the Offshore Electrical Connection Cable(s) within which they will be located. This area will comprise the marine components of the Proposed Development which are contained between the Offshore Array and landfall(s).
Offshore Platforms	Collective term for the platforms located within the Offshore Array, including the Offshore Operations & Maintenance Base/ Accommodation Platform, Offshore Substations (OSS) and Offshore Converter Stations (OCS).
Offshore Substation (OSS)	Platforms located within the Offshore Array which house electrical equipment and control and instrumentation systems, used for transforming the power (increasing the voltage). They also provide access facilities for work boats and helicopters.
Onshore Infrastructure	The combined name for all onshore infrastructure associated with the Project from landfall to grid connection, including the terrestrial electrical cable and onshore substation.
The Proposed Development	The infrastructure assets within the Offshore Array (Wind Turbine Generators, Array Cables, Interlink Cables, Offshore Platforms and UK Transmission Assets), the Offshore Electrical Connection Cables and landfall associated assets (Transition Joint Bays, a landfall logistics compound and associated access points), all contained within Isle of Man jurisdiction.

Term	Definition
Terrestrial Electrical Connection Cable	The Electrical Cable(s) between the Transition Joint Bay(s) at landfall and the Onshore Substation.
Transition Joint Bay (TJBs)	The offshore and onshore cable circuits are jointed in a Transition Joint Bay (TJB), typically located on the landward side of Mean High Water). The TJB is an underground chamber constructed of reinforced concrete which provides a secure and stable environment for the cable.
UK Transmission Assets	The transmission assets (electrical cables, potential offshore HVAC booster station, landfall, onshore cables (UK) and onshore substation (UK)) that transport power from within the Offshore Array to the UK, located within Isle of Man and UK jurisdictions.
UK Transmission Assets in the Offshore Array	The section of the UK Transmission Assets (electrical cables) situated within the Offshore Array that transport power from the Offshore Array to the UK.
UK Transmission Asset Funnel	The area outside the Offshore Array within which the UK Transmission Assets may exit the AfL area (e.g., Electrical Cables to National Grid in the UK) and terminate in other jurisdictions (the UK).
Wind Turbine Generator (WTG)	All the components of a wind turbine above the foundation, including the tower, nacelle, and rotor.

Abbreviations and Acronyms

Term	Definition
AfL	Agreement for Lease
ALARP	As Low as Reasonably Practicable
AtoN	Aids to Navigation
BOA	Breadth Overall
CAA	Civil Aviation Authority
CBRA	Cable Burial Risk Assessment
CTV	Crew Transfer Vessel
DAA	Developable Area Approach
DCO	Development Consent Order
DoI	Department of Infrastructure
EIA	Environmental Impact Assessment
ES	Environmental Statement
GIS	Geographical Information System
HDD	Horizontal Directional Drilling
HSE	Health, Safety and Environment
HVAC	High Voltage Alternating Current

Term	Definition
HVDC	High Voltage Direct Current
IOMCAA	Isle of Man Civil Aviation Administration
JB	Joint Bay
LAT	Lowest Astronomical Tide
LOA	Length Overall
LSE	Likely Significant Effect
MCA	Maritime Coastguard Agency
MDS	Maximum Design Scenario
MHW	Mean High Water
MMO	Marine Management Organisation
MU	Manx Utilities
NLB	Northern Lighthouse Board
NtM	Notice to Mariners
O&M	Operations and Maintenance
OCS	Offshore Converter Station
OECC	Offshore Electrical Connection Cable
OnSS	Onshore Substation
OSS	Offshore Substation
PRoW	Public Rights of Way
PSA	Protected Sites Assessment
Q1	Quarter 1
RoI	Republic of Ireland (Eire)
RtM	Route to Market
SCADA	Supervisory Control and Data Acquisition
SOV	Service Operations Vessel
TCPA	Town and Country Planning Act
TECC	Terrestrial Electrical Connection Cable
TJB	Transition Joint Bay
UK	United Kingdom
UKHO	United Kingdom Hydrographic Office
UXO	Unexploded Ordnance
WSI	Written Scheme of Investigation
WTG	Wind Turbine Generator

Units

Term	Definition
%	Percent

Term	Definition
°	Degrees
dB (decibel)	The scale on which sound pressure level is expressed. It is defined as 20 times the logarithm of the ratio between the root-mean-square pressure of the sound field and a reference pressure (2 x 10-5 Pa).
km	Kilometres
km^2	Kilometre squared
m	Metres
m^2	Metres squared
min	Minute
str	Strikes (hammer)
Y	year

1 Introduction

1.1.1.1 This Chapter of the Preliminary Environmental Information (PEI) Materials for the Mooir Vannin Offshore Wind Farm (Whole Project; see section 3) provides a description of the design and activities associated with the Construction, Operation and Maintenance (O&M) and Decommissioning of the Proposed Development (see section 3.2), defined as the infrastructure assets within the Offshore Array (Wind Turbine Generators, Array Cables, Interlink Cables, Offshore Platforms and UK Transmission Assets), the Offshore Electrical Connection Cables (OECC) and landfall associated assets (Transition Joint Bays, a landfall logistics compound and associated access points), all contained within the jurisdiction of the Isle of Man, as shown in Figure 1-1.

1.1.1.2 This Project Description provides a description of the:

- Design envelope approach (see section 1.2);
- Consultation summary (see section 2);
- Mooir Vannin Offshore Wind Farm (the 'Whole Project') (see section 3);
- Proposed Development (see section 3.2)
- Terrestrial Transmission Assets (see section 3.3)
- O&M Facilities (see section 3.4)
- UK Transmission Assets (see section 3.5)
- Proposed Development Maximum Design Scenario (see section 4);
- Construction Programme (see section 4.10)
- Operation, maintenance and decommissioning activities (see section 4.11); and
- Commitments made by the Applicant (see section 5).

1.1.1.3 This Project Description reflects the updates to the project design that have progressed since submission of the Mooir Vannin EIA Scoping Report in October 2023, namely:

- The removal of the Terrestrial Electrical Cable Connection (TECC) and Onshore Substation (OnSS) from the Proposed Development in the Isle of Man, further explained in paragraph 1.1.1.4;
- The progression of the Applicant's Route to Market (RtM) assessment which has concluded that a connection to Penwortham on the English west coast is to be progressed as part of the Whole Project (referred to as the UK Transmission Assets).
- Refinement of the Mooir Vannin Offshore Wind Farm's design, notably:
  - Removal of Douglas Promenade as a landfall option;
  - Inclusion of Port Skillion (outer Douglas Bay) as a landfall option; and
  - Removal of Gravity Base Foundations from the design envelope; and
- Provision of additional and updated technical design parameters and methodologies, including an increase in monopile hammer energy to 6,600 kJ and pin-pile hammer energy to 5,000 kJ.

1.1.1.4 The Applicant has taken the decision to progress the TECC and OnSS on the Isle of Man described in the Mooir Vannin Offshore Wind Farm Scoping Report in a separate consenting timeframe to the Proposed Development. This is to allow the promoter of this infrastructure to further mature the technical design. The terrestrial transmission assets are therefore not part of the Proposed Development in this Project Description. Further information on this decision is provided in Chapter 1, Introduction (Chapter will be made available at Application).

1.1.1.5 The Mooir Vannin Offshore Wind Farm will also export power generated by the Proposed Development to England via a radial connection that will make landfall and grid connection outside of the Isle of Man jurisdiction. These works are therefore subject to separate consents (hereafter referred to as UK Transmission Assets). The Applicant is also considering a connection to the Republic of Ireland, the related assets for which are referred to as the Eire Transmission Assets, but this is in the very early stages of development and does not form part of the Whole Project. Operation & Maintenance (O&M) facilities on the Isle of Man are continuing to be matured, which will be subject to a separate Isle of Man consent.

1.1.1.6 In addition to the Proposed Development, this Project Description describes the aforementioned terrestrial transmission assets on the Isle of Man, the UK Transmission Assets and the O&M facilities for the purpose of describing the 'Whole Project', hereafter (see Figure 3-1), to ensure the application considers all aspects of the development. This approach is set out further in Chapter 5, EIA Methodology with the 'Whole Project' assessed in the Cumulative Effects Assessment (CEA) Methodology (Volume 1, Annex 5.2) (Chapters will be made available at Application).

1.1.1.7 This chapter has been prepared to support the proposed application for a Marine Infrastructure Consent (MIC) under the Marine Infrastructure Management Act 2016 (MIMA 2016) for the parts of the Proposed Development seaward of Mean High Water (MHW), subject to the provision set out in Section 7(3) of MIMA 2016 for the inclusion of proposed works that are partly within and outside the Controlled Marine Area being enacted in the MIMA regulations.

1.1.1.8 The final design of the Proposed Development will be refined after consent has been granted and will fall within the parameters stated within this Project Description. This Chapter therefore sets out a series of options and parameters for which maximum values are used to identify a Maximum Design Scenario (MDS), defined within the technical topic-specific tabs of the Impacts Register (Volume 1, Annex 5.1), for the Proposed Development, with the final project being less than or equal to the MDS assessed.

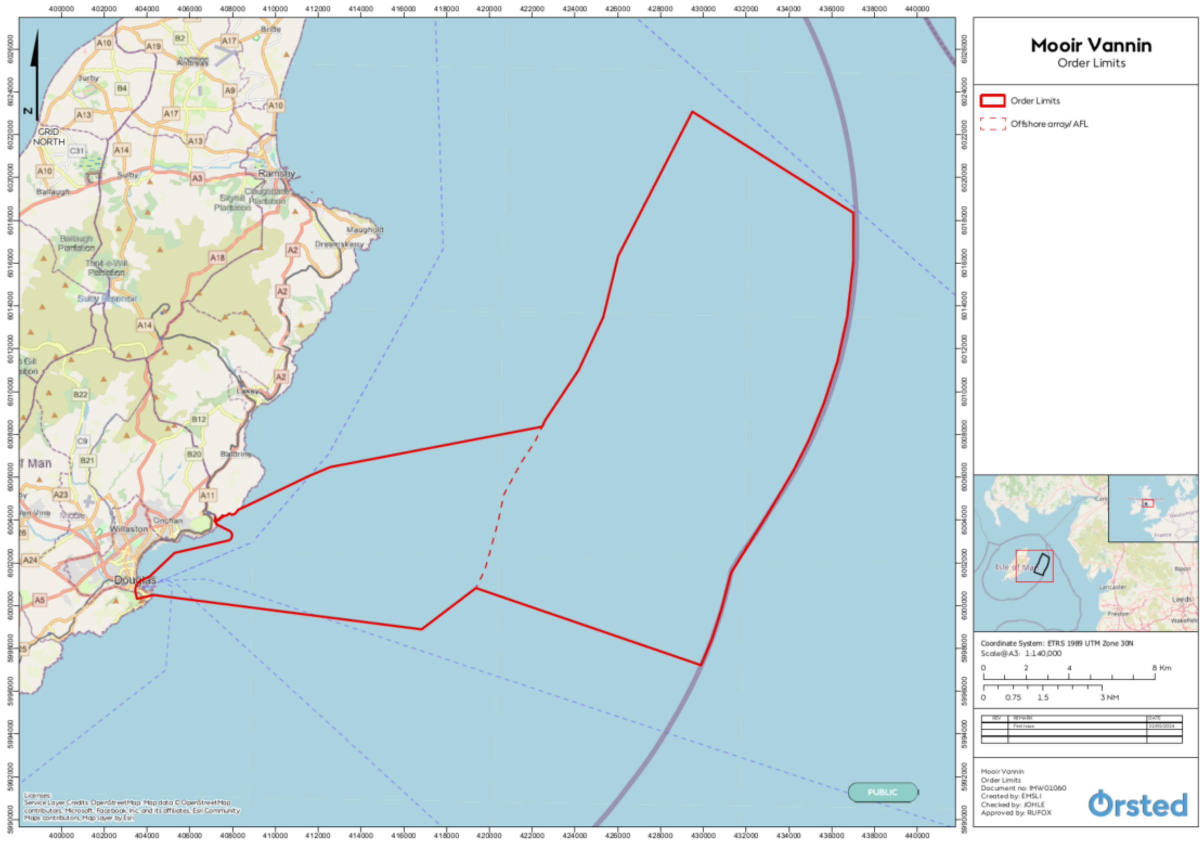

Figure 1-1 Order Limits for the Proposed Development

1.2 Design Envelope Approach

1.2.1.1 The consenting process for the Proposed Development (and the 'Whole Project') will be progressed using the design envelope approach. The design envelope sets out the maximum extents of a project for which significant effects are established within the project's EIA and will inform the basis on which consent is sought for the project. The detailed design of the Proposed Development can then vary within this 'envelope' whilst maintaining the validity of the EIA. This approach allows the consideration and analysis of the maximum impacts that could occur from a range of designs and parameters whilst enabling meaningful assessment and building in reasonable flexibility for future design decisions to be made on the Proposed Development.

1.2.1.2 At this stage in the development process, the Project Description is therefore indicative and based on the Applicant's extensive experience in building and operating 12 offshore wind farms within the UK and having two additional assets (Hornsea Three and Hornsea Four) in various stages of development.

1.2.1.3 The 'envelope' has been designed to include a necessary degree of flexibility to accommodate further project refinement during detailed design, post-consent. The Proposed Development requires flexibility so that design decisions can be made post-consent, such as choice of foundations options, transmission technology (i.e., HVAC or HVDC), specific siting of infrastructure and construction methodologies to ensure that anticipated changes in available technology and project economics can be accommodated within the consent obtained for the Proposed Development. The final design will depend on factors including ground conditions, wave and tidal conditions, seabed obstructions, project economics and procurement approach. This chapter therefore sets out the maximum design parameters for the Proposed Development, which are encompassed within the Design Envelope.

2 Consultation

2.1.1.1 As part of the EIA process for the Proposed Development, a Scoping Opinion was obtained from the Isle of Man Government on 7 June 2024, following submission of the Mooir Vannin Scoping Report (Orsted, 2023) on 18 October 2023.

2.1.1.2 Consultation received in the Scoping Opinion and other consultation responses of relevance to the Project Description has been considered in the development of this Chapter. Table 2-1 provides a summary of key points raised and describes how they have been addressed.

Table 2-1 Summary of consultation responses and where issues are addressed.

Consultation date and type	Consultee	Key issue raised	How comment has been/ is being addressed
07/06/24 – Scoping Opinion	Department of Infrastructure	The Project Description should ensure accuracy and refinement to ensure a full assessment of the impacts can be undertaken on a robust and realistic worst case design envelope. The project should show clear division of the onshore and offshore elements of the project and those that are outside of Manx territory.	The Design Envelope Approach undertaken by the Applicant defines a Maximum Design Scenario for the Proposed Development, which is then refined through iterations at each consent milestone (Consultation, 2024 and Application, 2025). The Project Description will clearly outline where this refinement has occurred and which elements of the project are onshore in the Isle of Man, offshore in the Isle of Man and outside of Isle of Man jurisdiction altogether, with the use of consistent terminology and figures.
		Where a separate application is required for any land elements of the Project, any impacts associated with these works should also be considered in the appropriate manner to satisfy the relevant legislative requirements.	The onshore elements of the project in the Isle of Man which do not form part of the Proposed Development in this Project Description, will be progressed in a separate consent application with the necessary environmental impact assessments carried out to satisfy the relevant legislation.
		The importance of retaining the flexibility achieved through the "Design Envelope" approach is recognised and supported by IOMG, though material changes cannot be made once an application is submitted. In order to ensure the decision-making process and flexibility are upheld, the IOMG requires that: 1. Rationale for the design envelope is provided. 2. Elements of the project yet to be finalised should be identified with reasons explaining this status. 3. Where design elements are not yet finalised, realistic parameter ranges / options should be	The Applicant intends to progress the preparation of the application in line with DoI's expectations and will continue to engage with DoI on these topics to discuss certain elements further. Specifically (corresponding to the numbered points): 1. The design envelope approach provides a necessary degree of flexibility to accommodate further project refinement during detailed design, post-consent. 2. Elements of the Proposed Development or Whole Project that are not yet finalised are

Consultation date and type	Consultee	Key issue raised	How comment has been/ is being addressed
		provided from which the final design will be selected. 4. Consideration should be given to changes to final project design to ensure they don't effectively constitute a material departure from the design assessed in the EIA. Further discussion between the Developer and IOMG is recommended on this topic. 5. It is expected that the Project design envelope needs to incorporate all temporary and permanent development associated with the Project within the AfL area as well as any offshore export cable corridor and any cable links to the Island requirements within Isle of Man territorial waters.	identified where options in their design currently exist e.g., foundation types for WTGs. This is in accordance with the design envelope approach to provide a necessary degree of flexibility to accommodate further project refinement during detailed design, post-consent. 3. Maximum Design Scenarios are provided for all parameters of the project, to ensure the EIA has assessed the all design scenarios within that envelope, with any final project design selected within this MDS therefore having been assessed. 4. The Applicant is preparing a Scoping Update document, capturing the changes in the project design and agreements with Statutory Consultees through the Evidence Plan Process, which will be submitted to DoI for their approval prior to submission of the application. 5. The Project Design Envelope will incorporate all activities that will be undertaken to construct, operate, maintain and decommission the Proposed Development, which is contained wholly within the Isle of Man's jurisdiction.
25/06/24 – Response to Scoping Consultation	Manx Utilities Authority	The need for the cables to be protected from damage, using sub-sea burial to a depth of 2m or alternative physical protection where cable is not possible.	Cable protection is described in the Project Description in Section 4.6.6, with cable burial as the preferred method of protection and the use of rock placement in other areas. The target burial depth for Offshore

Consultation date and type	Consultee	Key issue raised	How comment has been/ is being addressed
			Cables will be determined based on an assessment of seabed conditions, seabed mobility and the risk of interaction with external hazards such as fishing gear and vessel anchors, though is currently proposed at 5 m depth at this stage in project design.
		Preference to avoid a Douglas cable landing due to the proximity to the existing interconnector.	Douglas Promenade has been removed as a potential landfall location, such that Groudle Bay and Port Skillion are the two landfall options for the offshore cables. The Applicant will continue to engage with Manx Utilities as the project design is refined, particularly with regards to cable routing and installation at Port Skillion.
		Onshore infrastructure required on the Isle of Man for the Eire Grid connection.	The Applicant can confirm that there will be no onshore infrastructure required on the Isle of Man for the potential connection to the Eire Grid. This potential transmission option is still undergoing evaluation and further information will be provided at Application.
		The impacts of planned onshore infrastructure in relation to MUA's existing infrastructure.	The Applicant can confirm that the onshore cable (Terrestrial Electrical Connection Cable) and the onshore substation have been removed from the Proposed Development and will instead be progressed in a separate application process.
		Communication, coordination and agreements in relation to subsea cables and proximity to existing MUA assets.	The Applicant is aware of the proximity of the Proposed Development to MUA's existing assets and will continue to engage closely with MUA to ensure any required agreements are made where relevant as the design of the Proposed Development progresses.
October 2024 - Response to Scoping Consultation	Cabinet Office	Personal wellbeing and residential areas in close proximity to onshore infrastructure	The onshore infrastructure of the Proposed Development is limited to the landfall area only, which is up to 250 m above Mean High Water and includes the

Consultation date and type	Consultee	Key issue raised	How comment has been/ is being addressed
			Offshore Cable (buried up to the Transition Joint Bay), the Transition Joint Bay(s) (underground concrete structures that house the joint of the Offshore Cable) and a temporary landfall construction compound, used to house the plant and equipment utilised during landfall works. All cables used for the Proposed Development will be EMF (Electro-Magnetic Field) Compliant, with an EMF Compliance statement to be submitted at Application in March 2025.

3 Mooir Vannin Offshore Wind Farm Overview

3.1.1.1 This overview provides a description of the Mooir Vannin Offshore Wind Farm (the 'Whole Project') as illustrated in Figure 3-1, which can be considered as four constituent parts listed in Table 3-1 with links to their descriptions within this chapter.

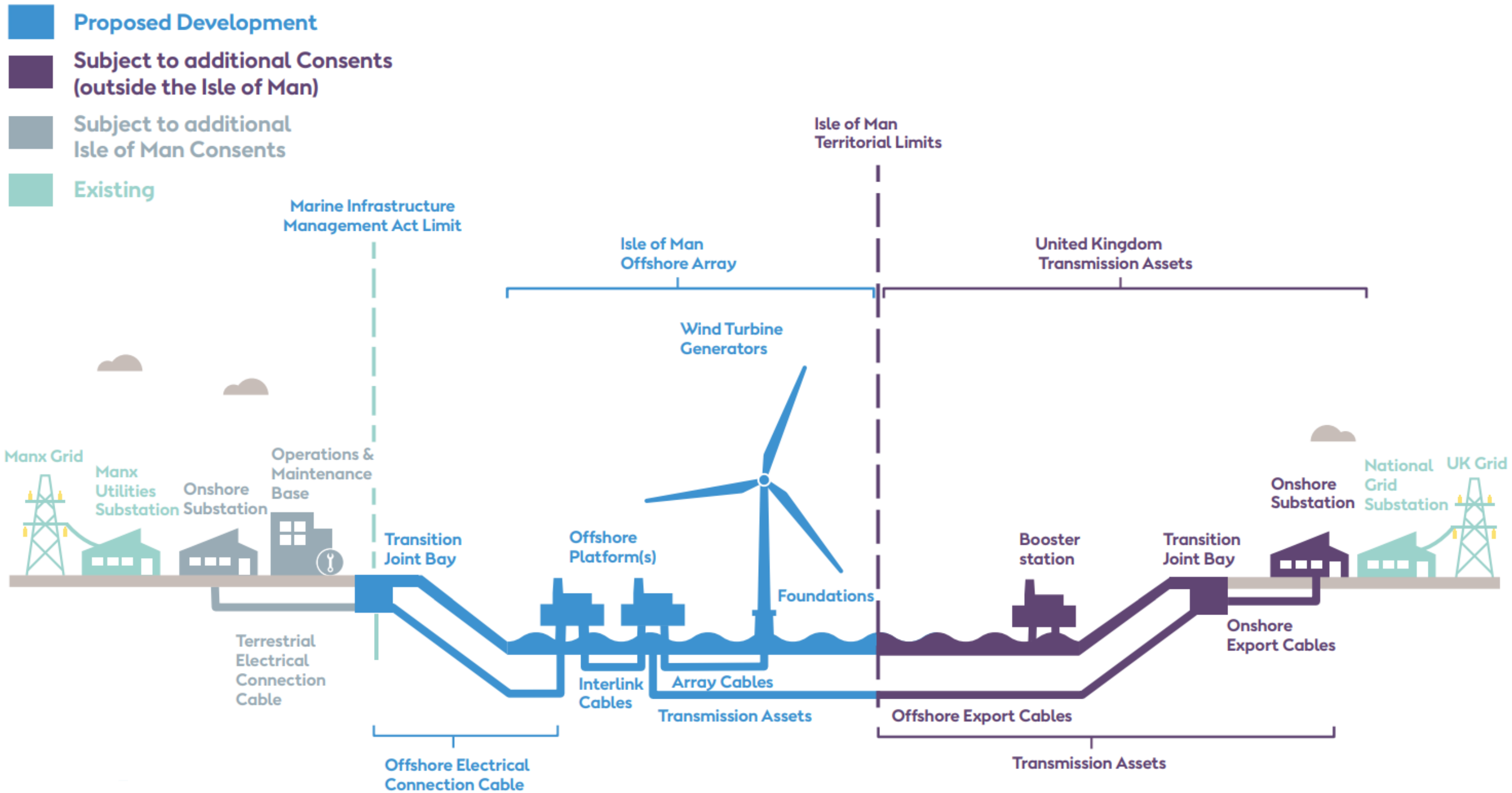

Figure 3-1. The Mooir Vannin Offshore Wind Farm (the 'Whole Project') with the Proposed Development (blue), assets subject to separate Isle of Man consents (grey) and the Transmission Assets subject to separate UK consents (purple).

Table 3-1 Constituent parts of the Mooir Vannin Offshore Wind Farm (the 'Whole Project')

Constituent	Located	Consent(s)	Described	MDS
Proposed Development	Wholly within the Isle of Man jurisdiction, the subject of this Project Description	MIC	Section 3.2	Section 4
Terrestrial Assets	Wholly within the Isle of Man jurisdiction	TCPA	Section 3.3	
O&M Facilities	Wholly within the Isle of Man jurisdiction	TCPA	Section 3.4	
UK Transmission Assets	Transmission assets to the UK contained wholly within UK jurisdiction.	DCO (UK)	Section 3.5	Section 3.5.2

3.2 The Proposed Development

3.2.1.1 The Proposed Development sits wholly within the Order Limits and consists of the following, as shown in Figure 3-1 and further described in Table 3-2.

3.2.1.2 The "Offshore Array": The generation asset (Wind Turbine Generators (WTGs) and Array Cables) and transmission asset (Interlink Cables and Offshore Platforms) infrastructure contained within the Agreement for Lease (AfL) area.

3.2.1.3 The "Offshore Electrical Connection Cables" (OECC): The Electrical Cables connecting the Offshore Platform(s) within the Offshore Array to the Transition Joint Bay(s) at the landfall location(s) on the Isle of Man, to be located within the Offshore Array, the Offshore Electrical Infrastructure Search Area (EISA) and at the landfall(s).

3.2.1.4 .

3.2.1.5 The landfall: the infrastructure associated with the landfall works at one or more landfall locations, including the Transition Joint Bays and any required landfall construction compound.

3.2.1.6 The "UK Transmission Assets in the Offshore Array": the transmission assets (Electrical Cables and any Offshore Substations) that will export power to the UK that are situated within the Offshore Array, as illustrated in Figure 1-1.

Table 3-2: The Proposed Development Key Components

Components	Assets	Purpose
Offshore Array	Wind Turbine Generators (MDS provided in section 4.3)	The Wind Turbine Generators (WTGs) convert wind energy into electricity. WTGs typically have three rotor blades, a nacelle (housing transformers, power electronics, control equipment and in some cases gearboxes) and a tower that are installed onto a WTG Foundation. As WTG technology is continuously improved, the exact model will be selected post-consent from the range of models available at the point of procurement.
	WTG Foundations (MDS provided in section 4.5)	WTG Foundations are typically installed into or onto the seabed and secure the WTG in place. The different types of Foundation designs under consideration are described further in this Project Description.
	Array cables (MDS provided in section 4.6.2)	Subsea cables buried in the seabed connect all WTGs together in strings and transport the power to an offshore substation/s.
	Offshore Platforms (Substations, Accommodation Platforms and/or Operation and Maintenance Base) and Interlink Cables (MDS provided in section 4.4 and 4.6.3 respectively)	An offshore platform may be an offshore substation, accommodation platform and/or an O&M base. An offshore substation converts the power from WTGs to higher voltages (Offshore Substation) to transmit the power more efficiently (by reducing electrical losses) to shore. An accommodation platform or offshore O&M base would facilitate personnel to carry out maintenance services offshore to reduce vessel trips to/from the offshore wind farm. In order to improve the reliability of the transmission system, interlink cables may be installed connecting the offshore platforms to each other.
	Scour, cable crossings and cable protection (MDS provided in section 4.5.6 (scour) and 4.6.6 (cables protection))	Scour protection is the placement of rock and/or other materials on the seabed to minimise scour from current and wave action around Foundation structures protecting the seabed and keeping the asset secure. Cable crossings involve the crossing of an existing asset (such as a 3rd party cable/pipeline) typically via the placement of a separation layer on top of the existing asset, laying of the cable then placement of cable protection (such as rock or concrete mattresses). Alternatively, 3rd party cables may be cut with the ends secured with a clump weight if confirmed to be redundant. Where cables can't be buried (due to cable crossings or stiff sediments etc.) the cable will be protected with a hard-protective layer (such as rock or concrete mattresses) to ensure that the cables remain secure, are not damaged and do not become a hazard to other sea users.

Offshore Electrical Connection Cable/s	Electrical Cables (MDS provided in section 4.6.5)	Subsea export cables buried in the seabed transport the power from the offshore substations to the landfall. Cables will be routed to avoid major seabed obstacles and minimise electrical losses. Cables are delivered in sections and jointed in-situ. Fiber-Optic cables are integrated into the power cables in an HVAC transmission and are bundled with the power cables in an HVDC system. They allow communication with the wind farm, collection of operational data and local and remote control of wind turbine functions. Whilst power cables ultimately terminate at an onshore substation, the Fiber-Optic Cables will terminate at an O&M base.
	Scour, cable crossings and cable protection (MDS provided in section 4.5.6 (scour) and 4.6.6 (cables protection))	Scour protection is the placement of rock and/or other materials on the seabed to minimise scour from current and wave action around foundation structures protecting the seabed and keeping the asset secure. Cable crossings involve the crossing of an existing asset (such as a 3rd party cable/pipeline) typically via the placement of a separation layer on top of the existing asset, laying of the cable then placement of cable protection (such as rock or concrete mattresses). Alternatively, 3rd party cables may be cut with the ends secured with a clump weight if confirmed to be redundant. Where cables can't be buried (due to cable crossings or stiff sediments etc.) the cable will be protected with a hard-protective layer (such as rock or concrete mattresses) to ensure that the cables remain secure, are not damaged and do not become a hazard to other sea users.
Landfall	Transition Joint Bay(s) (TJB) and landfall compound(s) (MDS provided in section 4.9)	Landfall infrastructure will include the Offshore Electrical Connection Cable/s, any associated Horizontal Directional Drill (HDD) assets, potential landfall construction compound/s and the Transition Joint Bay/s within those compounds. Transition Joint Bays (TJB) are underground concrete structures that house the joint between the Offshore Electrical Connection Cables and the Terrestrial Electrical Connection Cables. The landfall compound(s) will also house other landfall plant and equipment that may be used to pull in and connect the offshore and onshore sections of cables.
UK Transmission Assets in the Offshore Array	(MDS provided in section 4.6.4)	The Electrical Cables situated within the Offshore Array that will transport power out of the Offshore Array from an Offshore Substation out of the Isle of Man jurisdiction towards the UK where they will make landfall. Note that only the portion of these Transmission Assets that are located within the Offshore Array are part of the Proposed Development as they are within the Isle of Man jurisdiction.

3.2.2 Transmission technology

3.2.2.1 There are two transmission technologies being considered for the Mooir Vannin Offshore Wind Farm, defined by the type of current: High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC). The Array Cables and Offshore Electrical Connection Cable/s of the Proposed Development will be HVAC, primarily due to the relatively short distance of the Proposed Development to the Isle of Man, which would require fewer physical cables than an equivalent HVDC transmission. The UK Transmission Assets will utilise HVAC or HVDC transmission, whilst project economics, route planning and technology risk are considered. The decision will be confirmed at a later stage, during detailed design and procurement. It should be noted that if a combination of the two technologies is used, the total infrastructure installed will not exceed the maximum values assessed within this Project Description.

3.2.3 Proposed Development location

3.2.3.1 The Proposed Development components and their locations are shown in Figure 3-1 and described in Table 3-2. The latter provides further site-specific context with a description of their physical environment in the following sections. A description of the baseline physical environment of the Proposed Development can be found in the Physical Processes Technical Baseline (Volume 3, Annex 1.1) (to be provided at Application).

Surface infrastructure layout

3.2.3.2 Designing and optimising the layout of the surface infrastructure (WTGs and Offshore Platforms) is a complex, iterative process that factors site conditions such as wind speed and direction, water depth, ground conditions, environmental constraints, seabed obstructions and the order limits (i.e., the site boundary), as well as design considerations such as the turbine, foundation and electrical design, installation set-up and O&M requirements.

3.2.3.3 The Applicant requires flexibility in location of the WTGs and Offshore Platforms, within the final approved layout, to ensure that anticipated changes in available technology and project economics can be accommodated within the Proposed Development's Design Envelope. To inform the EIA, an indicative layout containing 100 potential WTG positions and the five potential Offshore Platform positions has been created and is shown in Figure 3-2 and conforms to the defined layout principles.

3.2.3.4 The layout principles are design criteria agreed in consultation with the relevant stakeholders (e.g., DoI) to inform the layout design of all surface infrastructure. The aim of the layout principles is to improve the final layout submitted by the Applicant taking account of the technical and consenting considerations at an early stage and thereby hopefully facilitating the final sign off for the layout. The layout includes a single line of orientation with a minimum spacing for all development scenarios between surface infrastructure (between tip-to-tip) of 500 m or 820m centre-to-centre. The final array layout will be approved by DoI in consultation with the MCA.

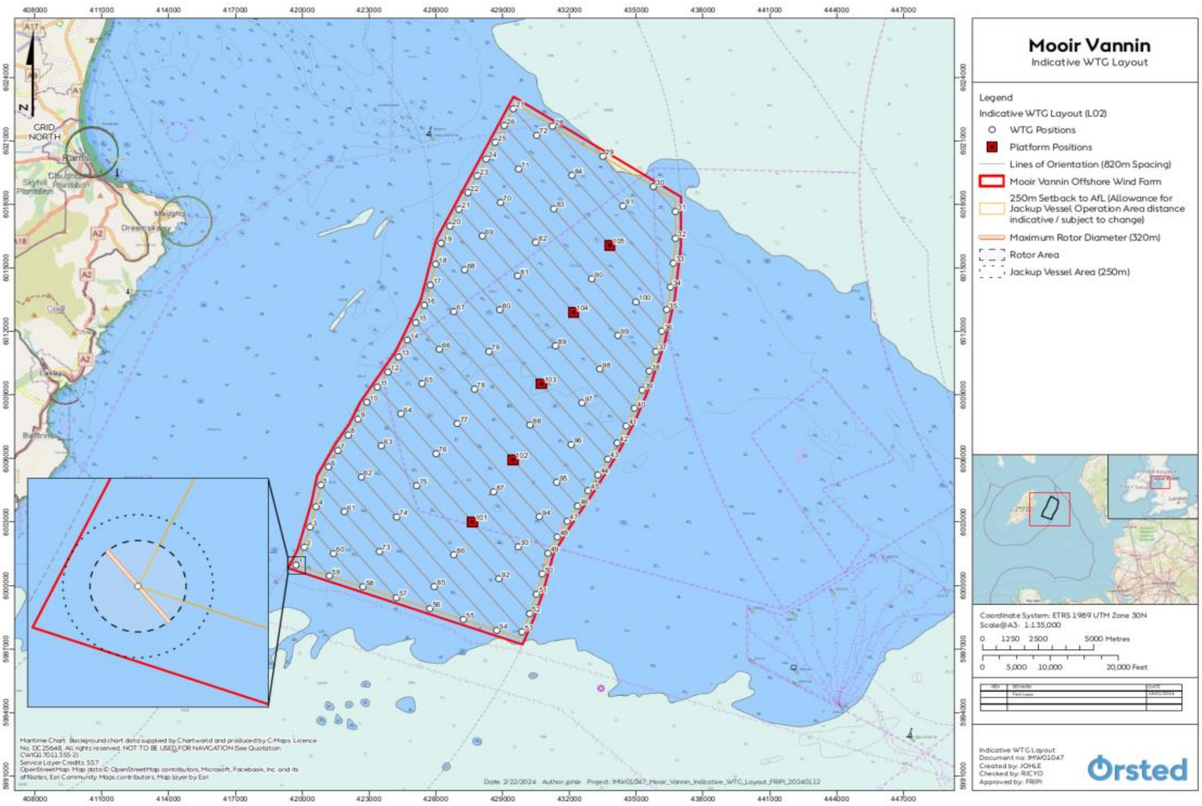

Figure 3-2 Indicative layout

Offshore Array

3.2.3.5 The Offshore Array area covers an area of 253km^2, wholly located within the Isle of Man Territorial Sea. The 12 nautical mile (nm) limit of the Isle of Man Territorial Sea forms its eastern boundary with the 6nm limit forms the Offshore Array's western boundary with Maughold as its closest point at approximately 11km. Water depths across the Offshore Array range from around 10m to 36m below Lowest Astronomical Tide (LAT), with an average water depth of 21.5m LAT and the deepest water located in the far north-east corner of the site, where the seabed slopes steeply. The seabed gradients over the rest of the site are generally shallow.

3.2.3.6 The seabed sediments over the site are generally coarse comprising sands and gravels, with a higher fraction of finer sediments in the north, grading to coarser sediments to the south. Boulders are found in limited deposits across the site. No rock outcrop was recorded. The most noticeable feature of the seabed is the prevalence and distribution of gravel ribbons exposed by high current velocities flowing in a south-west to north-easterly direction.

3.2.3.7 Geophysical surveys carried out in April and May 2024 collected data on seabed conditions, bathymetry and obstacles to develop the project's understanding of the ground conditions within the Offshore Array to further inform siting of infrastructure for the final EIA in the submitted Application.

Offshore Electrical Connection Cable

3.2.3.8 The Offshore Electrical Connection Cable/s travel approximately south-west from the Offshore Array to the landfall on the Isle of Man's east coast with landfall either at Port Skillion (outer Douglas Bay) or Groudle Bay, routed within the Offshore Electrical

Connection Search Area (ECSA). The geophysical surveys carried out in April and May 2024 included the Offshore ECSA to inform the Route Planning process and final EIA for the Offshore Electrical Connection Cables.

Landfall

3.2.3.9 The Offshore Electrical Connection Cable/s will make landfall on the east coast of the Isle of Man, either at Port Skillion (Outer Douglas Bay) and/ or Groudle Bay, as shown in Figure 3-3. The landfall at Port Skillion would involve routing of the OECCs alongside the existing Manx 1 interconnector to a Transition Joint Bay (TJB) above MHW, contained within a landfall compound.

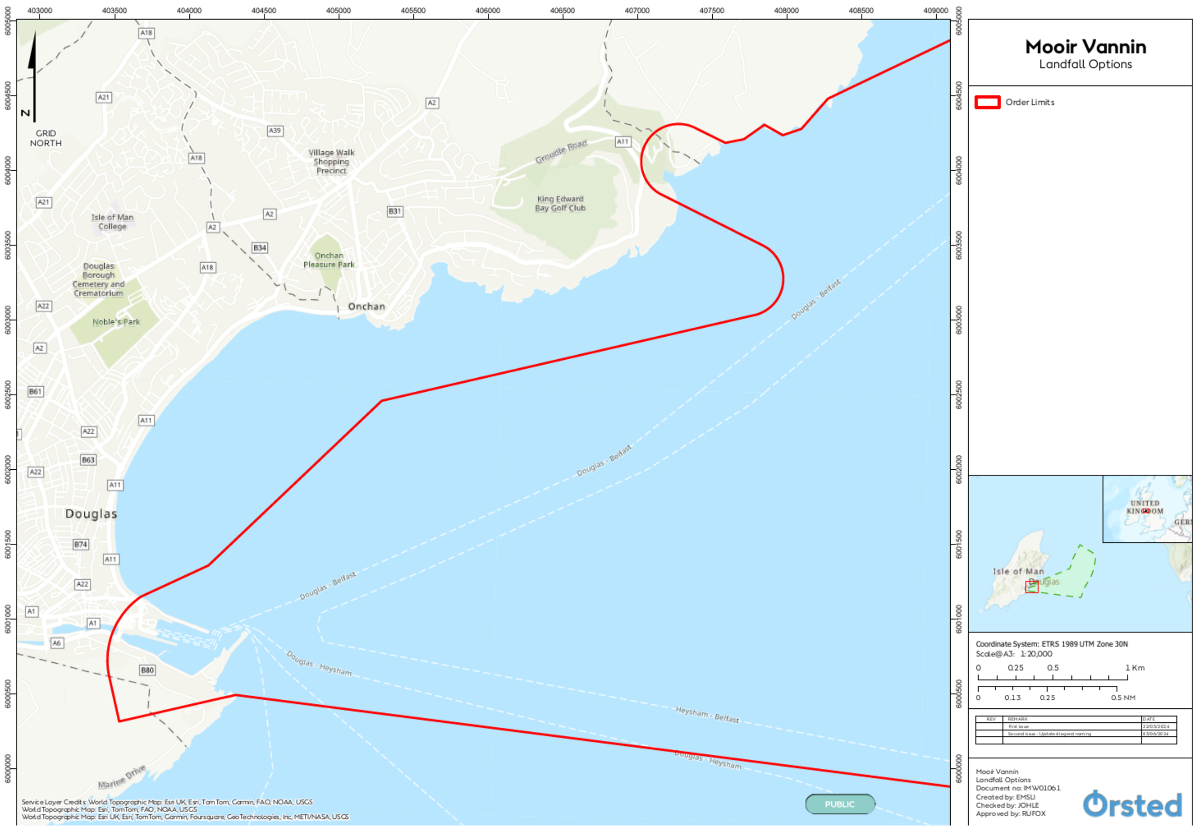

Figure 3-3 Landfall options at Groudle Bay and/or Port Skillion

UK Transmission Assets in the Offshore Array

3.2.3.10 The UK Transmission Assets include subsea electrical cables that will transport electricity from within the Offshore Array to an onshore substation in Penwortham, England before connecting to a National Grid substation in Penwortham, potentially via an Offshore Booster Substation in the event of utilising HVAC transmission, situated approximately halfway between the Offshore Array and Onshore Substation in the UK, subject to actual site conditions. The routing of these transmission assets is subject to the ongoing Route Planning and Site Selection (RPSS) process. The UK Transmission Assets start within the Offshore Array, are routed via the Transmission Asset Funnel (defined as an area equal to the length of a tidal excursion, which is the upper limit of sediment transport and deposition and limit of any potential Likely Significant Effects (LSE) to arise) to landfall in the UK. The UK Transmission Assets within the Offshore Array are considered part of the Proposed Development. The Transmission Asset Funnel is described for its potential to give rise to cumulative and transboundary effects on receptors within the Offshore Array and those outside of both are defined only to provide an understanding of the 'Whole Project'.

3.2.3.11 The Maximum Design Scenario for the UK Transmission Assets are described in section 4.6.4.

3.3 Terrestrial transmission assets (Isle of Man)

3.3.1.1 The terrestrial transmission assets, comprised of the TECC and the (OnSS), are not part of the Proposed Development and will be consented separately under the Town and Country Planning Act (TCPA, 1998) by either the Applicant or Manx Utilities at a later stage.

3.3.1.2 A description of these terrestrial transmission assets and their Maximum Design Scenarios (MDS) are provided below to provide an understanding of the 'Whole Project'.

3.3.2 Terrestrial Electrical Connection Cable (TECC)

3.3.2.1 The TECC(s) are electrical cables buried in the ground that transport power from the TJB(s) at landfall in Port Skillion (Outer Douglas Bay) to the OnSS (if the decision is to land at Groudle Bay, a third party such as Manx Utilities will take responsibility for consenting and/ or constructing the onshore cable). Cables will be delivered and installed in sections, connected within jointing bays and protected (e.g., via burial in trenches), which will subsequently be reinstated to pre-existing condition as far as reasonably practical. Jointing Bays (JB) are underground concrete structures that house the joint connecting the sections of the Terrestrial Electrical Connection Cables.

3.3.2.2 Cable installation is a well-established technique and will incorporate environmental management and mitigation measures as standard practice. All cables will be installed by one or a combination of open-cut trenches and trenchless techniques such as horizontal directional drills (HDD). HDD is a trenchless method where cable is pulled directly through pre-drilled underground sections and is typically used for crossing features that cannot be trenched i.e., cliff faces or sea defences at landfalls. Precise installation methods will differ according to the nature of the environment through which the cable is being installed. It has been designed to create the least environmentally damaging and most cost-effective approach to cable construction.

3.3.3 Onshore Substation

3.3.3.1 The Onshore Substation will be sited in an area in proximity to an existing Isle of Man Substation at Lord Street or Middle River in Douglas and will house all necessary electrical infrastructure to align the voltage and meet the requirements of protecting the connection and isolating the transmission network, including Grid Connection Cable(s) to the Isle of Man Substation.

3.3.3.2 The Proposed Development's HVAC transmission system to the Isle of Man operates at a different voltage level to the Isle of Man's transmission network, due to the higher voltage of# the WTGs. As such, the Onshore Substation will house a power transformer and other associated electrical infrastructure to adapt to the voltage for the Isle of Man network. The equipment will either be housed within a building(s), in an open compound or a combination of the two.

3.3.3.3 The maximum design parameters of the Terrestrial Electrical Connection Cable and Onshore Substation is shown in Table 3-3.

Table 3-3 Maximum Design Scenario: Onshore Infrastructure

Is Component	Parameters	Maximum design parameters
Terrestrial Electrical Connection Cable	Number of cables	9 (3 x 3 single core cables) (3 per HVAC circuit)
	Number of trenches	3 (one per circuit)
	Installation	Direct-lay in trenches, and/ or pulled through pre-installed ducting
	Permanent construction corridor width	45 m
	Temporary construction corridor width	60 m
Onshore substation	Temporary footprint of site	6700 m^2
	Dimensions of buildings	45 x 80 m
	Number of main buildings	1
	Height of main building	25 m
	Number of grid connection cables	2

3.4 Onshore Operation & Maintenance (O&M) Facilities

3.4.1.1 The onshore O&M facilities are not part of the Proposed Development but will be used to support it, so are subject to a separate Isle of Man consent application and form part of the 'Whole Project'. The Proposed Development does include an option for one of the Offshore Platforms to be utilised as an Offshore O&M Base. The onshore O&M facilities will likely be sited within, or in close proximity to, Douglas Harbour, made up of offices and a warehouse/s alongside the quayside, facilitating the transportation of personnel and equipment from the harbour out to the Offshore Array via a Crew Transfer Vessel (CTV) or Service Operational Vessel (SOV). Where the required space is not wholly available within, or in close proximity to, Douglas Harbour, a warehouse for storage and additional office space may be located outside the harbour. The full O&M requirements are in development and the exact nature and location of facilities will be determined in consultation with Department of Infrastructure (DoI).

3.4.1.2 Whilst the physical onshore O&M facilities are not part of the Proposed Development, the activities associated with the operations, maintenance and decommissioning phase of the Proposed Development are and will therefore be assessed in the EIA. An overview of these activities is provided separately in section 4.11.2.

3.4.1.3 An overview of the onshore O&M facilities on the Isle of Man and their maximum design parameters is provided in Table 3-4 to inform the whole Project Description of the Mooir Vannin Offshore Wind Farm.

Table 3-4 Maximum Design Scenario: onshore Operations & Maintenance facility on the Isle of Man

Component	Parameters	Maximum design parameters
O&M Base	Number of main buildings:	2 (office and warehouse)
	Area of harbour facility, quayside and pontoon	7,800 m^2
	Area of warehouse, offices and accommodation	1,700 m^2
	Total area (land plot):	9,500 m^2
	Footprint:	3,800 m^2
	Height of offices:	12 m
	Height of warehouse & workshop:	10 m
Quayside	Footprint	100 m x 16 m.
Crew Transfer Vessel (CTV)	Maximum depth LAT:	5 m
	Length overall (LOA):	35 m
	Breadth overall (BOA):	10 m
Service Operation Vessel (SOV)	Maximum depth LAT:	8.5 m
	Length overall (LOA):	120 m
	Breadth overall (BOA):	25 m

3.5 UK Transmission Assets

3.5.1.1 This Section provides a description of the radial connection from the Offshore Array to Penwortham, England (UK).

3.5.1.2 The UK Transmission Assets will utilise a HVAC/HVDC transmission system, comprised of Offshore Export Cables, an Offshore Booster Station (in the event of HVAC), landfall infrastructure, Onshore Export Cables, an Onshore Substation and Grid Connection Cables to connect to a National Grid Substation at Penwortham in the UK. These assets, in the context of the 'Whole Project', including the relevant consents required and jurisdictions, are illustrated in Figure 3-4. Also

3.5.1.3 The Offshore and Onshore Cables routes, and the locations of the Offshore Booster Station (if required) and Onshore Substation are subject to ongoing Route Planning and Site Selection (RPSS) process, balancing technical feasibility, environmental constraints and commercial viability.

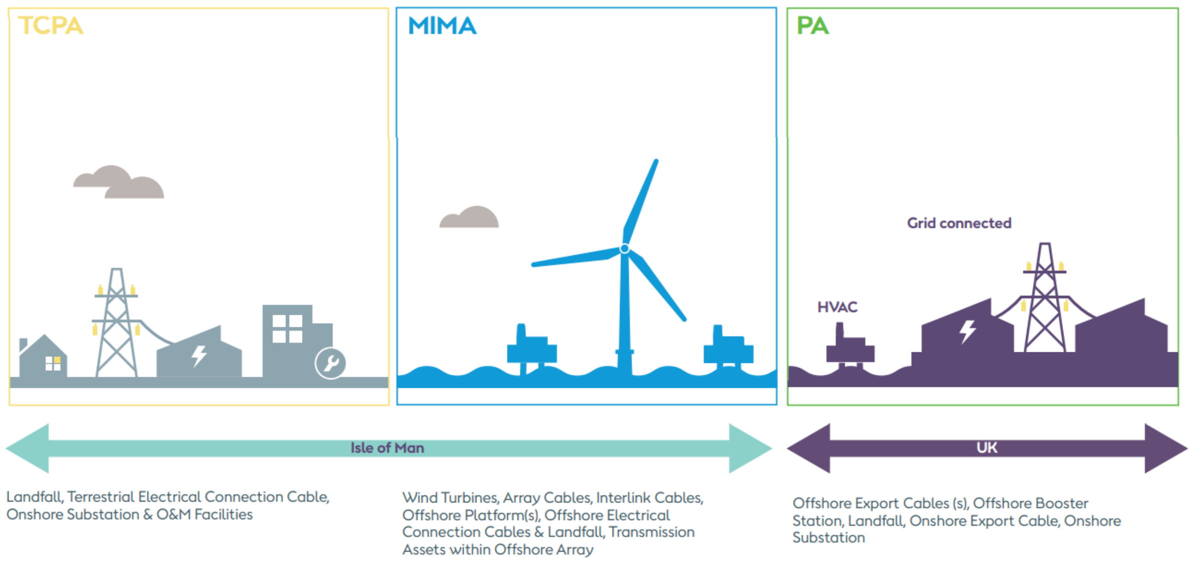

Figure 3-4 Mooir Vannin Offshore Wind Farm (Whole Project), with required Consents and relevant jurisdictions. NOTE: PA is Planning Act 2008 (England & Wales), MIMA is Marine Infrastructure Management Act 2016 (Isle of Man) and TCPA is Town and Country Planning Act 1999 (Isle of Man).

3.5.1.4 The technical specifications and Maximum Design Scenarios for these Transmission Assets are currently defined to sufficient detail herein to allow the reader to understand the scale and complexity of the Whole Project.

3.5.1.5 As the Route Planning and Site Selection process for these Transmission Assets progresses, further technical details will be provided with refinement of the design over time in accordance with the Design Envelope Approach (described further in section 1.2 and Annex 5.A, Proportionate EIA Position Paper, to be provided at Application).

3.5.2 UK Transmission Assets– Maximum Design Scenario

3.5.2.1 The Offshore Export Cables will comprise up to five subsea power cables in the event of HVAC, or up to four export cables (in two circuits) in the event of HVDC.

3.5.2.2 An Offshore Booster Station, sited approximately mid-way between the Offshore Array (Isle of Man) and the Onshore Substation (UK) on the Offshore Export Cable route, would be required in the event of HVAC, to compensate for the electrical losses that occur in an AC system when transporting electricity over longer distances.

3.5.2.3 An overview of the maximum design parameters for the UK Transmission Assets in the Offshore Array is outlined in Table 3-5.

Table 3-5 UK Transmission Assets Maximum Design Scenario (MDS)

Component	Parameters	MDS Values
Offshore export cables	Total number	5 (in 5 circuits)
	Permanent offshore construction corridor width	1,200 m
	Temporary offshore construction corridor width	1,400 m
HVAC Offshore Booster Stations	Number	1
	All other MDS parameters are as per the 'Small/Medium' concept Offshore Transformer Substation described in section 4.4.3 and 4.5.	
Landfall	Permanent landfall construction corridor	100 m
	Temporary landfall construction corridor	200 m
Onshore export cables	Total number	15 (in 5 circuits)
	Permanent construction corridor	65 m
	Temporary construction corridor	85 m
OnSS / converter station	Temporary footprint	166,000 m^2
	Permanent footprint	63, 000 m^2
	Height	30 m

4 Proposed Development: Maximum Design Scenario

4.1.1.1 This section provides the maximum design scenario for all the components of the Proposed Development described in Table 3-2.

4.1.1.2 Where applicable, the following sections provide a description of the design and installation activities, followed by the maximum design parameters for each of these components.

4.1.1.3 All infrastructure will be fabricated offsite, transported to and stored at a suitable port facility and then transported to site when required with specialist transport and installation vessels. An initial review of suitable ports has been undertaken, with a list of indicative installation ports provided below. It should be noted that this list is not finalised, and ports may be included or excluded from this list as further assessment is undertaken. Douglas Port is not suitable as an installation harbour due to factors such as storage space limitations and water depths, though may be considered as an Engineering, Procurement and Construction (EPC) base in the event that O&M is carried out from Douglas Port as well. The maximum number of vessels, helicopters and return trips to the Proposed Development from port or airfield required for each scope throughout construction and operation are listed in section 4.7 and section 0 respectively.

4.1.1.4 From an initial desktop study, one or more of the following ports may be utilised for the Construction phase of the Proposed Development. The approximate distance to the Offshore Array is also provided.

- Holyhead (Wales) (60 km)

- Mostyn (Wales) (62 km)
- Belfast (Northern Ireland) (74 km)
- Rossalare (Eire) (144 km)
- Port Talbot (Wales) (235 km)
- Inch Green (Scotland) (138 km)

4.2 Infrastructure Overview

4.2.1.1 The main components of the Proposed Development are shown in Figure 4-1 and listed in Table 4-1 with a link to the sections in this document where their full descriptions and maximum design parameters can be found.

Table 4-1 Main components of the Proposed Development

Component	Maximum number / length / area	Section
Wind Turbine Generators (WTGs)	100	4.3
Offshore Operations and Maintenance (O&M) Base / Offshore Accommodation Platform	1	4.4.2
Offshore Substations (OSS)	4	4.4.3
Offshore Converter Station (OCS) (HVDC only)	1	4.4.4
The maximum number of above-surface structures within the Offshore Array is 105. As such, either four Offshore Transformer Substations or one HVDC Offshore Converter Station will form part of the Proposed Development and should not be combined in the total number.		
Maximum hammer energy (WTG Foundations)	6,600 kJ	4.5.2
Maximum hammer energy (Offshore Platform Foundations)	5,000 kJ	4.5.3
Array Cables	490 km	4.6.2
Interlink Cables	100 km	4.6.3
UK Transmission Assets (within Offshore Array)	125 km	4.6.4
Offshore Electrical Connection Cables	90 km	4.6.5
Scour Protection (WTG Foundations, Offshore Platform Foundations)	1,091,190 m^2, 83,923 m^2	4.5.6
Cable Protection	Up to 15% of each cable route	4.6.6
Landfall	13,000 m^2	4.9

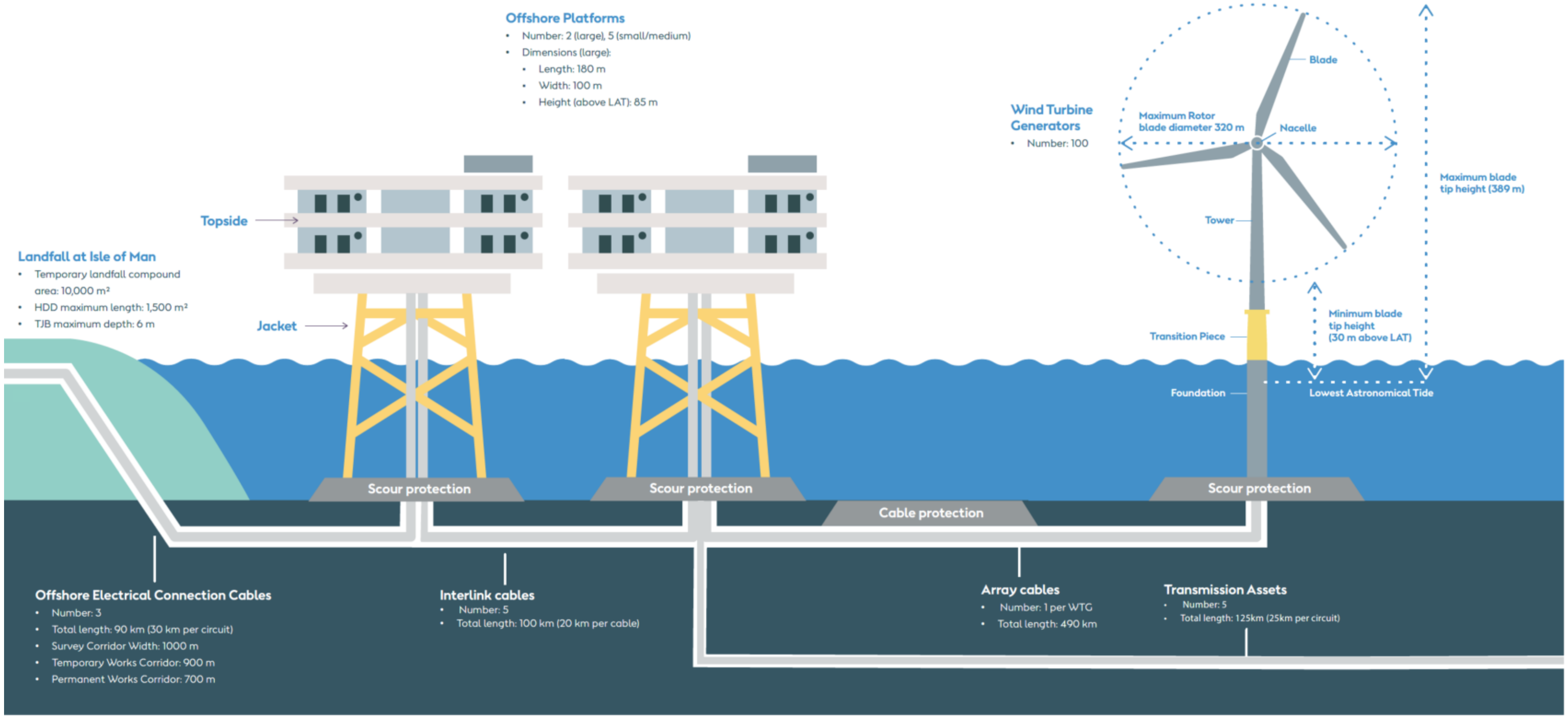

Figure 4-1 Overview of Proposed Development Infrastructure

4.3 Wind Turbine Generators (WTG)

4.3.1 Design

4.3.1.1 The Proposed Development may construct up to 100 WTGs. A range of WTG models will be considered though they will follow the traditional design with three blades and a horizontal rotor axis. The blades will be connected to a central hub, forming a rotor which turns a shaft connected to the generator or gearbox (if required). The variable-pitch blade can be manipulated to adjust power output in variable wind speeds and function as the 'brake' to slow or stop rotation to allow for maintenance to be carried out safely. The generator and gearbox will be located within a containing structure known as the nacelle situated adjacent to the rotor hub. The nacelle will be supported by a tower structure affixed onto a foundation structure. The nacelle will be able to rotate or 'yaw' on the vertical axis to face the oncoming wind direction and the blades will pitch if required.

4.3.2 Installation

4.3.2.1 WTGs are installed onto WTG foundations, typically in the following process:

- From the loadout port, WTG components (blades, nacelles, and towers) are picked up and transported offshore onboard an installation vessel/s. This vessel will typically be a Jack Up Vessel (JUV) to ensure a stable platform for installation when on site. JUVs are assumed to have up to six legs with a maximum spud-can area of 290 m^2 per foot. The installation vessel will typically carry components for several turbines during a single trip.
- The installation vessel/s will then transit to the Offshore Array area and the components will be lifted onto the existing transition piece or foundation substructure, by the crane on the vessel. Each WTG will be assembled on site in this fashion with technicians fastening components together as they are lifted into place. The exact methodology for the assembly is dependent on WTG type and installation contractor, and will be defined in the pre-construction phase after grant of consent; or
- Alternatively, the WTG components may be loaded onto barges or dedicated transport vessels at port and installed as above by an installation vessel that remains on site throughout the installation campaign.

4.3.2.2 The maximum total duration of the installation campaign for WTGs, including the transition piece, tower, nacelle and blades is anticipated to be 20 months.

4.3.2.3 The WTG installation vessels and barges may be assisted by a range of support and transport vessels. These typically smaller vessels may be tugs, guard vessels, crew transfer vessels, anchor handling vessels, or similar. These vessels will primarily make the same movements to, from and around the Offshore Array area as the installation vessels they are supporting.

4.3.2.4 The WTGs may be accessed either from a vessel via a boat landing or a stabilised gangway via the foundation or transition piece, or by hoisting from a helicopter to a heli-hoist platform on the nacelle. Any helicopter access would be designed in accordance with relevant guidance and standards (Isle of Man Civil Aviation Administration (IOM CAA) and UK Civil Aviation Authority (CAA).)

4.3.2.5 The maximum design parameters for WTGs are presented in Table 4-2 and illustrated with labels of the various WTG components in **Error! Reference source not found.**.

Table 4-2 Maximum Design Scenario: WTG

Parameter	Maximum Design Parameters
Number of WTGs	100
Rotor diameter	320 m
Maximum blade tip height above LAT	389 m
Minimum blade tip height above LAT	30 m

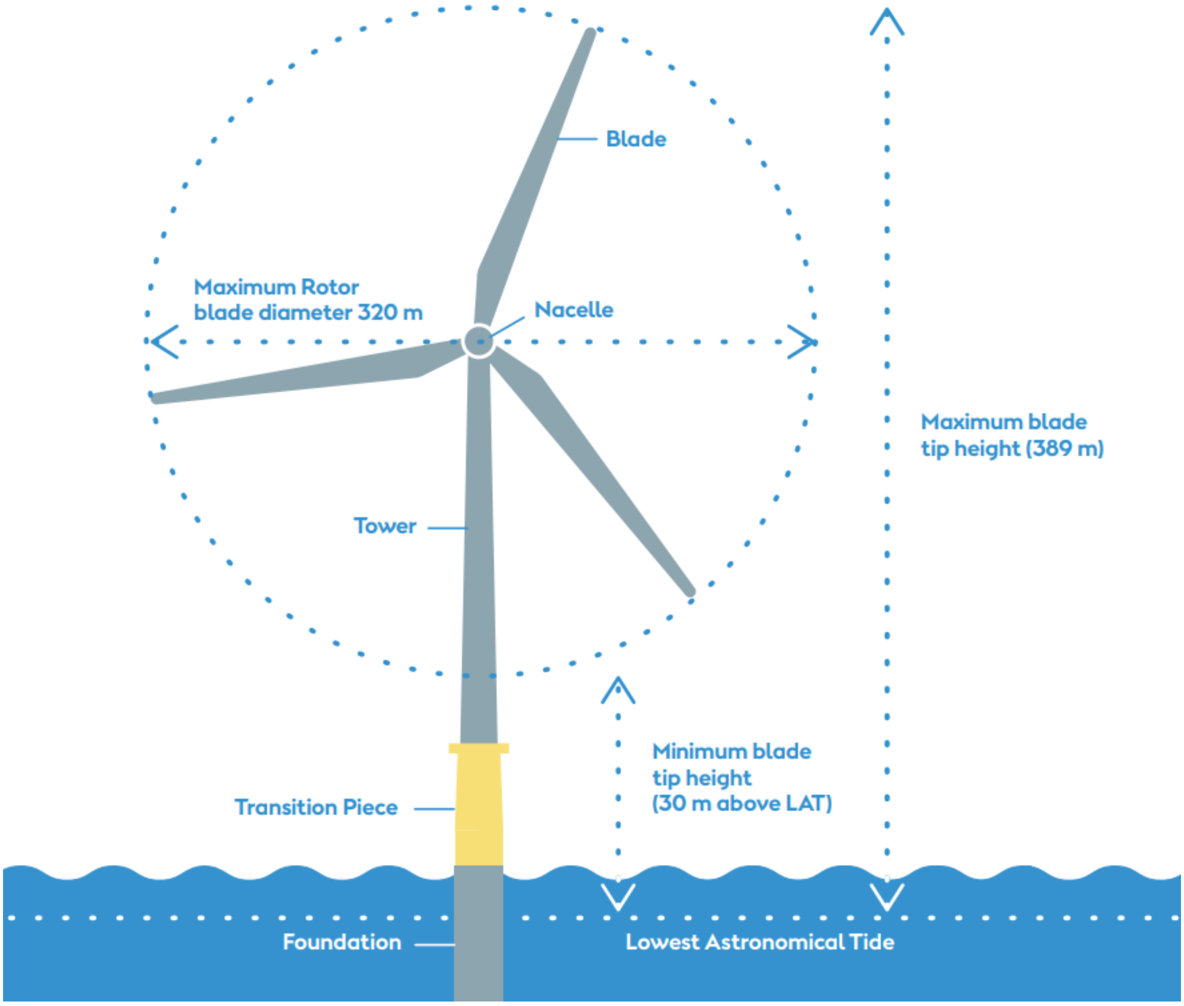

Figure 4-2 Maximum Design Parameters of a typical indicative Wind Turbine Generator

4.4 Offshore Platforms

4.4.1.1 Offshore Platforms include the following structures installed offshore:

- Offshore Operations and Maintenance (O&M) Base or Offshore Accommodation Platform;

- Offshore Substation (OSS); and
- Offshore Converter Stations (OCS) (HVDC only)

4.4.1.2 There will be a maximum of up to five Offshore Platforms in the Offshore Array. Offshore Substation(s) (OSS) will be utilised if the transmission system for the UK Transmission Assets is HVAC and Offshore Converter Stations (OCS) if the transmission system is HVDC. The Offshore Substations and Offshore Converter Station will either be a 'large' concept design, with a maximum of one OSS or OCS, or a 'small/medium' concept design, with a maximum of four OSSs or OCSs. Either an Offshore O&M Base or an Offshore Accommodation Platform will be selected, not both (and neither if an onshore O&M strategy is taken). As such, the two potential scenarios for Offshore Platforms are the 'small/medium concept', with one Offshore O&M Base/ Accommodation Platform with four 'small/medium' concept OSSs or the 'large' concept, with one Offshore O&M Base/ Accommodation Platform with one 'large' concept OSS/ OCS.

4.4.1.3 The maximum design parameters for these configurations are summarised in Table 4-3.

Table 4-3 Maximum Number of Offshore Platform Types

Parameter	Maximum Design Parameters
Number of Offshore Platforms (total)	5
Number of Offshore O&M Bases or Offshore Accommodation Platforms	1
Number of Offshore Substations (OSS)	4
Number of Offshore Converter Stations (OCS)	1

4.4.1.4 It may be beneficial to site multiple different Offshore Platforms next to each other so that access can be gained from one to the other. In this case, bridge links may be constructed at deck level between the Offshore Platforms, each with a length of up to 100 m, as illustrated in Figure 4-3.

4.4.2 Offshore O&M Base and Offshore Accommodation Platform

4.4.2.1 An Offshore Operations & Maintenance (O&M) Base or an Offshore Accommodation Platform may be constructed by the Applicant to allow up to 150 operations staff to be housed within the Offshore Array for several weeks at a time, along with spares and equipment to perform maintenance tasks. By siting these platforms offshore, the number of trips and time spent in transit to and from the Offshore Array is reduced.

Design

4.4.2.2 An Offshore Accommodation Platform comprises of a platform with one or more decks and a helicopter platform, attached to the seabed by means of a foundation. The offshore accommodation platform will contain accommodation, storage, workshop and logistic facilities for operating and maintaining the wind turbine generators and housing auxiliary equipment, facilities for operating, maintaining and controlling the substation and to access the substation by vessels and helicopters. The offshore accommodation platform may also be co-sited with offshore substations, including bridge access (bridge links) between the platforms.

Installation

4.4.2.3 The typical installation process for the Offshore O&M Base and Offshore Accommodation Platform is as described for the Offshore Transformer Substations in section 4.4.3.

4.4.2.4 The maximum design parameters for the O&M Base and Offshore Accommodation Platforms are presented in Table 4-4.

Table 4-4 Maximum Design Scenario for Offshore O&M Base and Offshore Accommodation Platform

Parameter	Maximum Design Parameters
Number	1
Main structure length	60 m
Main structure width	85 m
Structure height above LAT (including auxiliary structures, though excluding antennae and masts)	64 m
Bridge link length	100 m
Number of operations staff	150

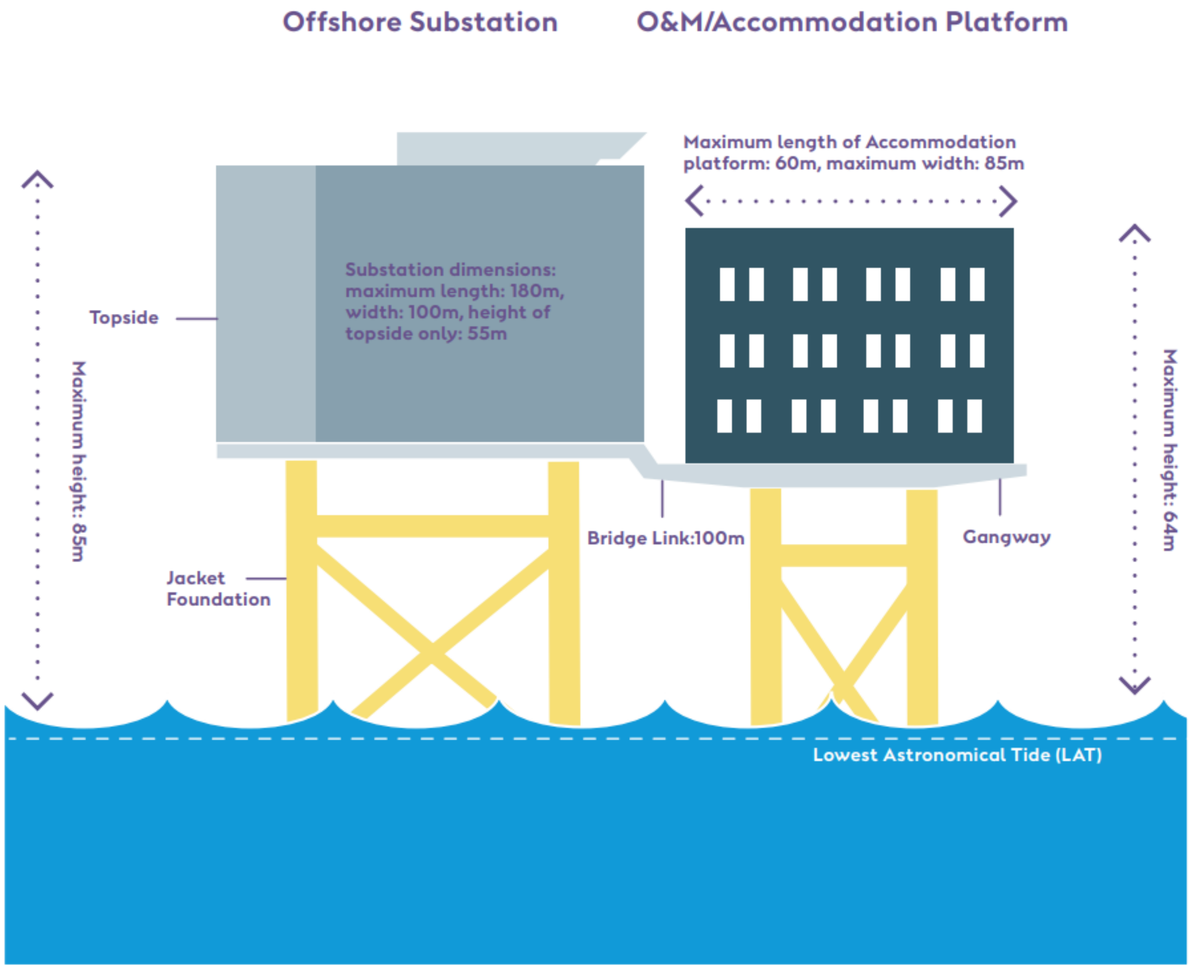

Figure 4-3 Offshore Substation and O&M/Accommodation Platform with bridge link

4.4.3 Offshore Substations

4.4.3.1 Offshore Substations (OSS) are offshore structures housing electrical equipment to 'step-up' the voltage with transformers housed within the main structure before transmission towards landfall by the Offshore Electrical Connection Cable/s.

4.4.3.2 Either a maximum of four OSSs will be constructed if a smaller size ('small/medium concept') is utilised or only one OSS if a larger size ('large concept') is opted for. The generic design and installation process does not vary greatly between the two.

Design

4.4.3.3 The OSS will comprise a platform known as a topside, with one or more decks and a helicopter platform, fixed to the seabed by means of a foundation. The topside contains equipment required to switch and transform electricity generated at the WTGs and may also house auxiliary equipment and facilities for operating, maintaining, controlling the substation and to access the substation by vessels and helicopters. Accommodation, storage, workshop and logistic facilities for operating and maintaining the WTGs may also be included, such as LiDAR.

Installation

4.4.3.4 An OSS is generally installed in two stages, firstly the foundation will be installed as described in section 4.5, secondly the topside will be lifted from a transport vessel or barge, onto the foundation. The foundation and topside may be transported on the same transport vessel or barge, or separately. The foundation may also be transported by the installation vessel.

4.4.3.5 The maximum design parameters for the 'small/medium' and 'large' options of the OSS are presented in Table 4-5 and a schematic of an OSS is illustrated in Figure 4-3.

Table 4-5 Maximum Design Scenario for Offshore Transformer Substation (OSS)

Parameter	Maximum Design Parameters	
	'Small/Medium'	*'Large'*
Number	4	1
Topside – main structure length	80 m	180 m
Topside – ancillary structure width	100 m	100 m
Topside height (including auxiliary structures, such as helipad, crane, lightning protection, however excluding antennae and masts above LAT)	75 m	85 m
Topside - thickness (height of topside from the top of the foundation)	45 m	55 m
Topside - area	8,000 m^2	18,000 m^2

4.4.4 Offshore Converter Substations (HVDC only)

4.4.4.1 An Offshore Converter Station (OCS) is only required in a HVDC transmission system so would only be required in the event that the UK Transmission Assets utilise a HVDC system. Offshore HVDC converter substations convert the three-phase AC power generated at the WTGs into DC power. The power is then transmitted via export cables towards the UK and converted back to AC in the UK for export to the grid.

Design

4.4.4.2 The design of the OCS is similar to that of the OSS, comprising a topside with one or more decks and a helicopter platform/heli-deck, fixed with a foundation to the seabed. The internal design will differ, in order to house the necessary equipment to convert and increase the voltage to HVDC (rather than transform it by just increasing the voltage as an OSS would). Only a larger size ('large concept') of the OCS is included in the design envelope for the Proposed Development.

Installation

4.4.4.3 The installation of the OCS is as the OSS, with the installation of the foundations as the first stage, followed by the topside, lifted from a transport vessel or barge, onto the foundation. Alternately, a float-over solution may be utilised, where buoyant structures are used to tow the structure to site using tugs.

4.4.4.4 The maximum design parameters for the 'large' option of the OCS are as per the 'large' OSS maximum design parameters presented in Table 4-5.

4.5 Foundations

4.5.1.1 The WTGs and Offshore Platforms are fixed to the seabed by foundation structures. The different types of foundation structures being considered for the Proposed Development are presented in Table 4-6. Those foundation types that are compatible with the surface infrastructure and therefore included within the design envelope are labelled 'Y' (Yes) and those that are not 'N' (No).

Table 4-6 Foundation options for WTGs and Offshore Platforms

Foundation Type	WTG	O&M Base / Offshore Accommodation Platform	OSS ('Small/Medium' concept)	OSS / OCS ('Large' concept)
Number	100	1	4	1
Monopile ('WTG type')	Y	Y	Y	Y
Piled Jacket ('WTG type')	Y	Y	Y	Y
Piled Jacket ('Small/Medium' concept)	N	Y	Y	Y
Piled Jacket ('Large' concept)	N	N	N	Y
Suction Caisson Jacket ('WTG type')	Y	Y	Y	Y
Suction Caisson Jacket ('Small/Medium' concept)	N	Y	Y	Y
Suction Caisson Jacket ('Large' concept)	N	N	N	Y
Mono-suction Bucket ('WTG type')	Y	Y	Y	Y

4.5.1.2 The foundation type and design used for the WTGs and Offshore Platforms may be a combination of different types and will be subject to development of a ground model and driveability assessments, as well as maintaining flexibility for the procurement of the foundation supplier(s), which will likely take place post-consent award.

4.5.1.3 All foundation types would be transported from the loadout port(s) to the Offshore Array by an installation vessel (JUV or Dynamic Positioning Vessel (DPV)) or on feeder barges. In all cases, a temporary works area with a 500 m diameter for construction vessels would be required around each foundation as a Safety Zone (further described in section 4.7.3).

4.5.1.4 Since submission of the Mooir Vannin EIA Scoping Report in October 2023, the Applicant has taken the decision to remove Gravity Base Foundations from the foundation options in the design envelope, due to a number of contributing factors. Gravity Base Foundations typically have the largest footprint area of the different foundation designs so their removal from the design envelope greatly reduces the potential maximum overall seabed footprint from the Proposed Development, the project has undertaken desk-based engineering assessments of the site conditions where it was concluded that Gravity Base Foundations were not a required option.

4.5.1.5 The key maximum design scenario values for the foundation types are shown in Figure 4-4. Inset A shows the key MDS values for WTG foundations, inset B shows the key MDS values in relation to seabed and working areas, inset C shows the key MDS values for all foundation types.

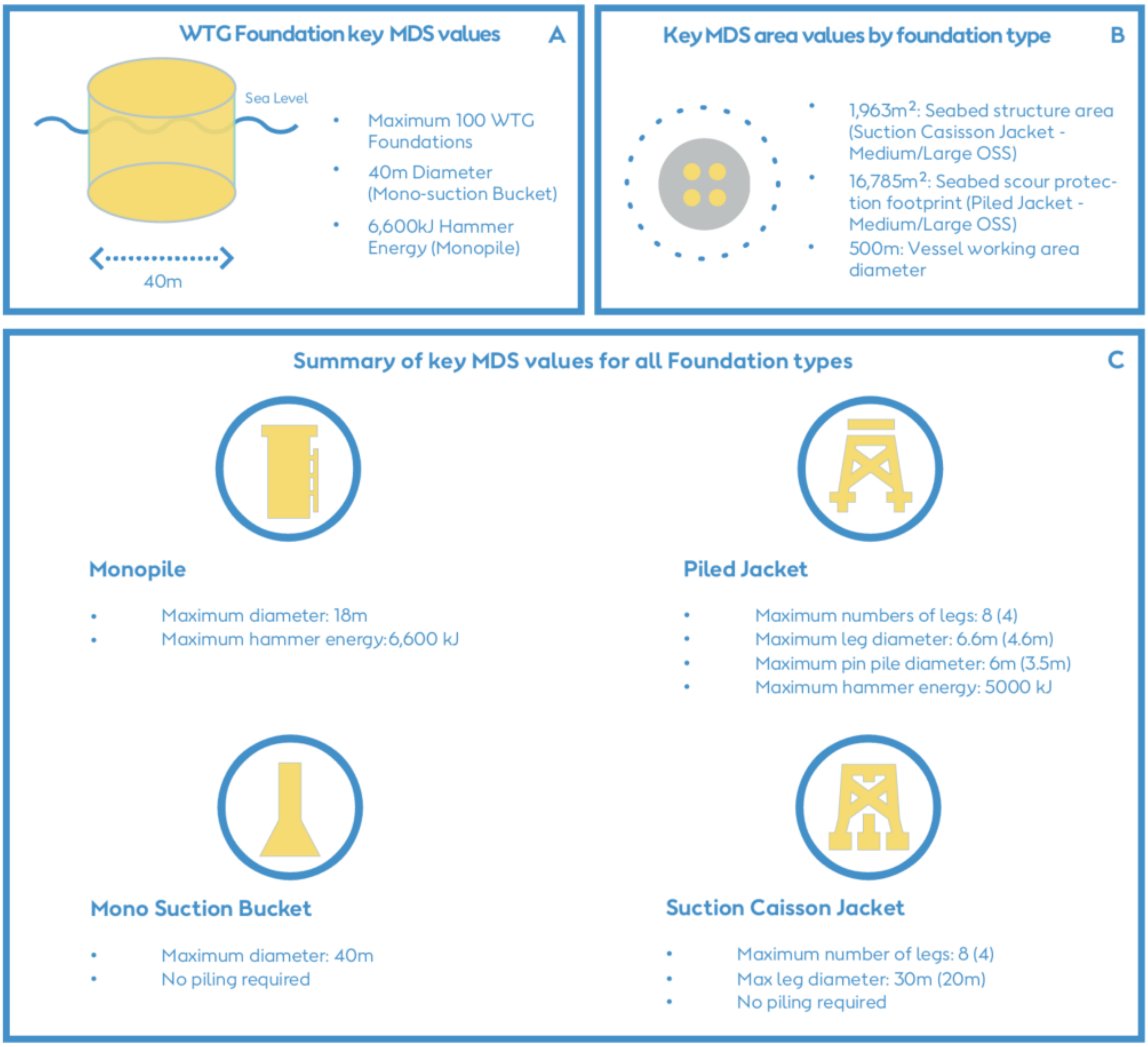

Figure 4-4 Key MDS values for all foundation types

4.5.1.6 A description of the design, installation methodology and maximum design parameters for each foundation type is provided in the following sections.

4.5.2 Monopile

4.5.2.1 Monopile foundations typically consist of a single steel tubular section, consisting of a number of sections of rolled steel plate welded together. For a WTG monopile foundation, a transition piece (TP) may be fitted over the top of the monopile and secured via a bolted connection. Secondary structures on each WTG monopile foundation will include a boat landing or alternative means of safe access, ladders, a crane, and other ancillary components (e.g., Get Up Safe – a motion-compensated hoist system allowing vessel to foundation personnel transfers without a boat landing). The TP may either be installed separately following the monopile installation or the monopile and TP may be fabricated and installed as an integrated single component. If the monopile and TP are fabricated and installed as an integrated component, the secondary structures will be installed on the TP subsequently and in separate smaller operations. For an OSS monopile, a module support frame (MSF) would be installed on the top of the monopile, acting as an "adaptor" (round to square) to support the OSS topside.

4.5.2.2 The following steps describe the typical installation of monopiles into the seabed:

- Lift monopile (with integrated transition piece) into the pile gripper on the side of the installation vessel;
- Lift hammer onto monopile and drive monopile into seabed to required embedment depth; (Alternatively, if deemed possible, the monopile can be jetted into the seabed, using small jets mounted on the monopile)
- Lift hammer from monopile and remove pile gripper;
- In the event that a separate transition piece is installed:
    - Lift transition piece onto monopile; and
    - Transition piece is bolted or grouted to the monopile. The grout used is an inert cement mix that is pumped into a specially designed space between the transition piece and the monopile.

4.5.2.3 Where conventional piling is unable to achieve necessary pile penetration, additional methods may be used (e.g., drilling, vibro- piling and/or electro-osmosis).

4.5.2.4 In the event that conventional piling is unable to achieve the necessary pile penetration, alternative or additional methods may be used, such as drilling, vibro-piling and/or electro-osmosis.

4.5.2.5 The maximum design dimensions of the monopile foundations are provided in Table 4-7.

Table 4-7 Maximum design parameters for monopiles

Parameter	Maximum Design Parameters
Number of piles per foundation	1
Diameter of monopile at the seabed	18 m
Diameter of the monopile at the sea surface	12 m
Typical embedment depth below seabed	50 m
Maximum impact hammer energy	6,600 kJ

4.5.3 Piled Jacket

4.5.3.1 Piled jacket foundations are formed of a steel lattice (comprising tubular steel members and welded joints) secured to the seabed by hollow steel pin piles attached to the jacket feet. The transition piece and ancillary structure is fabricated as an integrated part of the jacket, similar to the TP-less monopile. Pin piles will typically have a smaller diameter than monopiles.

4.5.3.2 Larger jackets may be required for the Offshore Platforms. These would have more legs and may also require the use of mud-mats, which are flat plates attached to the bottom of the jacket legs to support the foundation structure before piles are installed (if piles are installed after the jacket). The Offshore Converter Stations (HVDC) / 'Large' Offshore Substations (HVAC) could each be supported by four jacket structures, or a single larger jacket.

4.5.3.3 For installation of Piled Jacket foundations, piles are either pre-installed or installed after the jacket. For pre-installed piles, the piling template is first placed on the seabed, piles are then installed, followed by the jacket which is lowered and fixed onto the piles. The alternative is to lower the jacket to the seabed and then install the piles to secure the jacket in place. In all cases, the pin piles are either driven, drilled or vibrated into the seabed.

4.5.3.4 It should be noted that the maximum number of piles per foundation for 'OSS / OCS (Large)' is sixteen due to some of the foundation legs requiring fewer piles than other legs.

4.5.3.5 The maximum embedment depth presented in Table 4-8 is used to model a single representative drill scenario as a MDS for a single foundation location. It is highly unlikely that foundations will be drilled to the maximum embedment depth for all locations, so a typical embedment depth, which represents a realistic average maximum depth is provided to inform the maximum total volume of drill arisings across all foundation locations.

4.5.3.6 The maximum design scenario for Piled Jacket foundations is shown in Table 4-8.

Table 4-8 Maximum design parameters for Piled Jacket foundations

Parameter	Maximum Design Parameters		
	WTG Type	*OSS ('Small/Medium')*	*OSS / OCS ('Large')*
Number of legs per jacket foundation	4	4	8
Piles per leg	1	3	3
Number of piles per foundation	4	12	16
Separation of adjacent legs at seabed level	65 m	70 m	100 m
Platform height above sea level (LAT)	40 m	30 m	30 m
Separation of adjacent legs at LAT	25 m	70 m	100 m
Leg diameter	6.6 m	4.6 m	4.6 m
Pin pile diameter	6 m	3.5 m	3.5 m
Typical embedment depth	90 m	85 m	85 m
Maximum embedment depth	120 m	120 m	120 m
Hammer energy	5000 kJ	5000 kJ	5000 kJ
Mud-mats footprint	810 m^2	400m^2 (per leg)	400 m^2 (per leg)

4.5.4 Suction Caisson Jacket

4.5.4.1 Suction Caisson Jacket foundations are formed with a steel lattice (comprising tubular steel members and welded joints) fixed to the seabed by suction caissons installed below each leg of the jacket. The suction caissons are typically hollow steel cylinders, capped at the upper end, which are fitted underneath the legs of the jacket structure.

4.5.4.2 For installation, the jacket is lowered onto the seabed, water is pumped out of the caisson/s, pulling the jacket into the seabed using the pressure difference between the inside and outside of the caisson. At the desired depth, the pump is turned off and the jacket is fixed securely in place. As the difference in pressure is used to secure the foundations, they do not require a hammer or drill and as with Piled Jacket and Mono-suction Bucket foundations, there is no separate transition piece. A thin layer of grout is then injected under each caisson to fill the air gap and ensure contact between the soil within the caisson, and the top of the caisson itself.

4.5.4.3 The maximum design parameters for jacket foundations with suction caissons are presented in Table 4-9.

Table 4-9 Maximum design parameters for Suction Caisson Jacket foundations

Parameter	Maximum Design Parameters		
	WTG Type	*OSS (Small / Medium)*	*OSS / OCS (Large)*
Number of legs per jacket foundation	4	4	8
Separation of adjacent legs at seabed level	65 m	70 m	100 m
Separation of adjacent legs at LAT	25 m	70 m	100 m
Caisson Bucket diameter	20 m	25 m	30 m
Caisson Bucket height above seabed	10 m	5 m	5 m
Typical embedment depth	25 m	25 m	30 m

4.5.5 Mono-suction Bucket

4.5.5.1 A Mono-suction Bucket consists of a single suction bucket supporting a single steel or concrete structure, which supports the WTG or Offshore Platform. As with the jacket structures and suction bucket foundations, this foundation type does not require a transition piece to be installed offshore.

4.5.5.2 The installation of a Mono-suction Bucket mirrors that of the Suction Caisson Jacket foundation: the jacket is lowered onto the seabed, water is pumped out of the bucket/s, pulling the jacket into the seabed using the pressure difference between the inside and outside of the bucket. At the desired depth, the pump is turned off and the jacket is fixed securely in place. As the difference in pressure is used to secure the foundations, they do not require a hammer or drill and as with Piled Jacket and Caisson Jacket foundations, there is no separate transition piece. A thin layer of grout is then injected under each bucket to fill the air gap and ensure contact between the soil within the bucket, and the top of the bucket itself.

4.5.5.3 The maximum design parameters for mono suction bucket foundations are presented in Table 4-10.

Table 4-10 Maximum design parameters for Mono-suction Bucket foundation.

Parameter	Maximum Design Parameters
Suction bucket diameter	40 m
Suction bucket height above seabed	10 m
Typical embedment depth below seabed	30 m

4.5.6 Seabed preparation for foundations

4.5.6.1 The installation of foundations may require some form of seabed preparation. For all foundation types, the removal of obstructions such as boulders or debris from installation locations may be required if the foundations cannot be microsited (up to 50 m from the initial agreed position). Excavation may also be required to retrieve debris below the seabed surface.

4.5.6.2 Suction Caisson Jacket and Mono-bucket Foundations may also require seabed levelling in the form of sandwave clearance to ensure that each leg of the foundation is placed at the same level to form a sealed chamber within each bucket, in order for the installation process, involving the removal of water from within the buckets, to be effective.

4.5.6.3 These activities and their maximum design parameters are provided in section 0.

Scour protection

4.5.6.4 Scour protection is designed to mitigate the undermining of foundation structures for the WTGs and Offshore Platforms by hydrodynamic and sedimentary processes, resulting in seabed erosion and subsequent scour hole formation. The shape of the foundation structure is an important parameter influencing the potential depth of scour hole formation. Several types of scour protection exist, including rock placement (large quantities of crushed rock), mattress protection and stone-filled bags.

4.5.6.5 The preferred scour protection solution may comprise a rock armour layer resting on a filter layer of smaller graded rocks. The filter layer can either be installed before the foundation is installed or afterwards. Alternatively, by using heavier rock material with a wider gradation, it is possible to avoid using a filter layer and pre-install a single layer of scour protection.

4.5.6.6 The design and installation process for scour protection required will vary for the different foundation types being considered for the Applicant. Flexibility in scour protection choice and timings for when it is installed (prior to or after foundation installation) is required to ensure that anticipated changes in available technology, project economics and understanding of the site conditions can be accommodated within the design of the Proposed Development.

4.5.6.7 The maximum diameter of the rocks used would be 1 m and the maximum thickness of scour protection layer would be 2.5 m. The maximum design parameters of scour protection for the Proposed Development are provided in Table 4-11.

Table 4-11 Maximum design parameters for scour protection

Parameter	Maximum Design Parameters
Total area of scour protection	1,175,113 m^2
Total volume of scour protection	2,392,188.5 m^3

4.5.7 Maximum design parameters by foundation type

4.5.7.1 As described in section 1.2, the design envelope approach assesses the design that presents the maximum design scenario for the relevant receptor(s) in each assessment within the EIA chapters. The following sections present the maximum design scenario for all WTGs (Table 4-12), Offshore O&M Base / Accommodation Platform (Table 4-13), OSSs and OCS (Table 4-14), with the corresponding foundation types (Monopile, Piled Jacket, Suction Caisson Jacket and Mono-suction Bucket) to inform the assessment for the relevant receptor(s).

Table 4-12 Maximum design parameters for WTGs by foundation type

Parameter	Maximum Design Parameters	Related foundation type
Number of WTGs	100	n/a
Number of piles	400	Piled Jacket
Seabed preparation area	1,020,100 m^2	Suction Caisson Jacket
Seabed structure area	125,664 m^2	Mono-suction Bucket
Seabed scour protection area	1,091,190 m^2	Piled Jacket
Seabed total permanent area	1,102,500 m^2	Suction Caisson Jacket & Piled Jacket
Drill spoil volume (average; assumes 10% drilling)	127,235 m^3	Monopile
Seabed preparation (spoil) volume	1,881,800 m^3	Suction Caisson Jacket
Scour protection volume	2,182.381 m^3	Piled Jacket
Pile-structure grout volume	27,143 m^3	Piled Jacket
Structure-seabed grout volume	87,965 m^3	Mono-suction Bucket

4.5.7.2 Table 4-13 presents the maximum design parameters for the Offshore O&M Base / Accommodation Platform. Each assessment within the relevant receptor chapter of the Application will consider the range of foundations options and assesses the foundation type which presents the maximum design scenario for the relevant receptor(s).

Table 4-13 Maximum design parameters for the Offshore O&M Base / Accommodation Platform by foundation type

Parameter	Maximum Design Parameters	Related foundation type
Number of Offshore O&M Base / Accommodation Platforms	1	n/a
Number of piles	16	Piled Jacket ('Large' OSS)
Seabed preparation area	12,321 m^2	Suction Caisson Jacket ('Small/Medium' OSS)
Seabed structure area	1,963 m^2	Suction Caisson Jacket ('Small/Medium' OSS)
Seabed scour protection area	16,785 m^2	Piled Jacket ('Small/Medium' OSS)
Seabed total permanent area	16,900 m^2	Piled Jacket ('Small/Medium' OSS)
Drill spoil volume (average; assumes 10% drilling)	1,272 m^3	Monopile
Seabed preparation (spoil) volume	57,245 m^3	Suction Caisson Jacket ('Small/Medium' OSS)
Scour protection volume	41,962.5 m^3	Piled Jacket ('Small/Medium' OSS)
Pile-structure grout volume	271 m^3	Piled Jacket ('WTG-type')
Structure-seabed grout volume	1,374 m^3	Suction Caisson Jacket ('Small/Medium' OSS)

4.5.7.3 Table 4-14 presents the maximum design parameters for the Offshore Substation(s) (OSS) (HVAC only) and Offshore Converter Station (OCS) (HVDC only). Each assessment within the relevant receptor chapter of the Application will consider the range of foundations options and assesses the foundation type which presents the maximum design scenario for the relevant receptor(s).

Table 4-14 Maximum design parameters for Offshore Transformer Stations (OSS) and Offshore Converter Stations (OCS – HVDC only) by foundation type

Parameter	Maximum Design Parameters	Related foundation type
Number of OSSs / OCSs	4 'Small/Medium' OSS	n/a
Number of piles	64	HVAC: 4x OSS with Piled Jacket (16 piles each)
Total seabed preparation area	49,284 m^2	HVAC: Suction Caisson Jacket ('Small/Medium' OSS)
Seabed structure area	7,854 m^2	HVAC: Suction Caisson Jacket ('Small/Medium' OSS)
Seabed scour protection area	67,138 m^2	HVAC: Piled Jacket ('Small/Medium' OSS)
Seabed total permanent area	67,600 m^2	HVAC: Piled Jacket ('Small/Medium' OSS)
Drill spoil volume (average; assumes 10% drilling)	5,089 m^3	Monopile
Seabed preparation (spoil) volume	228,980 m^3	HVAC: Suction Caisson Jacket ('Small/Medium' OSS)
Scour protection volume	167,845 m^3	HVAC: Piled Jacket ('Small/Medium' OSS)
Pile-structure grout volume	1,086 m^3	Piled Jacket ('WTG-type')
Structure-seabed grout volume	5,498 m^3	HVAC: Suction Caisson Jacket ('Small/Medium' OSS)

4.5.8 Piling

4.5.8.1 The MDS for Monopile foundation installation (piling) will assume a maximum six-hour piling duration (actual time spent piling). Analysis of piling records at other Ørsted wind farms (Burbo Bank Extension, Walney Extension, Race Bank, Hornsea One and Hornsea Two) indicates that piling of monopiles typically averages two to three hours for installation (including the slow start procedure), with timings slightly longer at the beginning of the construction phase and then reducing as experience is gained. The maximum installation duration for a Monopile foundation, including preparation and breaks in the piling activity is 36 hours.

4.5.8.2 The MDS for Piled Jacket foundation installation assumes a maximum nine-hour piling duration per pin pile. The number of positions where piling work exceeds four hours is typically a small percentage, around 5% or less; this exceedance will likely be due to a higher penetration depth, breaks in the construction work caused by particularly challenging ground conditions or break-down of equipment and therefore does not reflect an uninterrupted four-hour start-to-finish hammer strike piling duration. The maximum installation duration for a pin-pile, including preparation and breaks in the piling activity is 48 hours. The typical piling installation duration for an Offshore Platform (with up to 16 pin-piles) is anticipated to be 192 hours (4 days).

4.5.8.3 The maximum hammer energy for the Proposed Development is 6,600 kJ for Monopile foundations. The rationale for using this hammer energy is to maximise the opportunity to successfully drive all piles. Although this hammer energy is considered as the maximum design scenario, the actual energy used when piling will be significantly lower for most of the time and the driving energy will only be raised to 6,600 kJ when necessary. To minimise fatigue loading on the monopiles, hammer energies are continuously set at the minimum required, which also reduces the likelihood of breakdown of the equipment, hence will typically start low (15% soft start of 990 kJ) and gradually increase to the maximum required installation energy during the piling of the final metres (typically significantly less than the maximum hammer energy).

4.5.8.4 As pin piles are smaller, the maximum hammer energy to be used would be 5,000 kJ.

4.5.8.5 The use of higher hammer energies may allow the maximum piling durations to be reduced. Other reasons why higher hammer energies are required include the greater effectiveness at pile driving (due in part to the additional weight of the hammer) and greater reliability, since they are working well below their design rating for much of the time. Knowledge of the anticipated construction work will improve as additional geoscience survey campaigns are undertaken and corresponding design work is completed for the Proposed Development, though this is not anticipated to be complete pre-Application.

4.5.8.6 A characteristic piling scenario with maximum durations for each energy level is provided for Monopiles (six-hours) and Pin piles (nine-hours) in Table 4-15.

Table 4-15 An indicative piling scenario for Monopile and Jacket Piled (pin piles) foundations.

% of maximum hammer energy	15%	20%	40%	60%	80%	100%
	Soft start	*Ramp up*				*Full*
Monopile blow energy (kJ)	990	1,320	2,640	3,960	5,280	6,600
Pin pile blow energy (kJ)	750	600	1,200	1,800	2,400	5,000
Strike rate (str/min)	3	30	30	30	30	30
Monopile duration (min)	30	37	40	40	40	160
Pin pile duration (min)	30	57	60	60	60	240

4.5.8.7 If piling is not possible due to the presence of rock or hard soils, the material inside the monopile may be drilled out before the monopile is driven to the required depth. This can either be done in advance of the driving or if the piling rate slows significantly during piling. If drilling is required, it is conducted at a speed of 0.5 to 1.0m/hr with any spoil arising from the drilling disposed of adjacent to the foundation location on the sea surface.

4.5.8.8 With regards to simultaneous installation of foundations with the use of multiple installation vessels, the only simultaneous piling that may occur is during the installation of the Offshore Platforms where two piling vessels may be piling the same or different Offshore Platforms within the Offshore Array. A maximum of eight piles for WTGs or Offshore Platforms may be drilled simultaneously across the Offshore Array.

4.5.8.9 It may also be possible that the piles are installed via alternative novel methods.

4.6 Offshore Cables

4.6.1.1 Offshore cables encompass the Array Cables (section 4.6.2), Interlink Cables (section 4.6.3), UK Transmission Assets (within the Offshore Array) (section 4.6.4) and the Offshore Electrical Connection Cables (section 4.6.5). The purpose, design, installation methodology, required protection and jointing and the associated maximum design parameters are presented for each offshore cable type in the following sections.

4.6.2 Array Cables

4.6.2.1 Array cables transport the electrical current produced at WTGs to an Offshore Substation (OSS) or HVDC Offshore Converter Station (OCS). A small number of turbines will typically be grouped together on the same Array Cable 'string,' connecting those turbines to the OSS/OCS.

4.6.2.2 The Array Cable transmission system will use HVAC technology with each cable consisting of several conductor cores, usually made from copper or aluminium surrounded by layers of insulating material, as well as armouring material to protect the cable from external damage.

4.6.2.3 The maximum design parameters for the Array Cables are presented in Table 4-17.

4.6.3 Interlink Cables

4.6.3.1 Interlink cables may be required between the Offshore Platforms to provide redundancy in the case of cable failure elsewhere, or to connect to the Offshore O&M Base / Accommodation Platform to provide power for operation.

4.6.3.2 The Interlink Cables will utilise HVAC transmission technology and will therefore have a similar design to the Array and Offshore Electrical Connection Cables.

4.6.3.3 The maximum design parameters for the Interlink Cables are presented in Table 4-17.

4.6.4 UK Transmission Assets (within the Offshore Array)

4.6.4.1 The UK Transmission Assets within the Offshore Array comprise of cables which will transport electrical power from one or more of the Offshore Substations, across the Offshore Array (AfL) and into English waters via the Transmission Asset Funnel, towards landfall in the UK.

4.6.4.2 The UK Transmission Cables may use HVAC or HVDC technology, with the design differing slightly between each. With HVAC, each cable contains the conductor core for transporting power and the fibre optic 'SCADA' cables within it, forming a 'circuit.' With HVDC, the conductor cores and SCADA cables are separate cables, which are bundled together into a single circuit.

4.6.4.3 The maximum design scenario for the portion of the UK Transmission Cables within the Offshore Array that form part of the Proposed Development is presented in Table 4-17.

4.6.5 Offshore Electrical Connection Cables

4.6.5.1 The Offshore Electrical Connection Cables will transport electrical power from the Offshore Array to the TJB(s) at the landfall location(s) on the Isle of Man utilising HVAC transmission technology.

4.6.5.2 The search area between the Offshore Array and the landfall location for potential routing of the Offshore Electrical Connection Cables is the Electrical Connection Search Area (ECSA), within which an installation corridor is defined.

4.6.5.3 The maximum design parameters for this corridor and the Offshore Electrical Connection Cables is provided in Table 4-16 and Table 4-17 respectively.

Table 4-16 Maximum design parameters for Offshore Electrical Connection Cable corridor

Parameter	Maximum design parameters
Length of Offshore Electrical Connection Cable corridor (excluding within Offshore Array)	28 km
Width of Offshore Electrical Connection Cable corridor (permanent cables)	700 m
Width of Offshore Electrical Connection Cable corridor (temporary works buffer)	200 m
Total width of Offshore Electrical Connection Cable corridor(s)	900 m

4.6.5.4 The maximum design parameters for all Offshore Cable types are presented in Table 4-17 with maximum lengths provided in Table 4-18.

Table 4-17 Maximum design parameters for all Offshore Cable types

Parameter	Maximum design parameters				
	Array Cables	*Interlink Cables*	*UK Transmission Cables*		*Offshore Electrical Connection Cable*
			HVAC	*HVDC*	
Number of cables (circuits if different)	1 per WTG (100)	5	5	8 (4)	3
Cable diameter	250 mm	350 mm	350 mm		250 mm
Voltage	170 kV	420 kV	420 kV	640 kV	170 kV

4.6.6 Installation of Offshore Cables

4.6.6.1 All Offshore Cables will be buried below the seabed wherever possible.

4.6.6.2 The target burial depth for Offshore Cables will be determined based on an assessment of seabed conditions, seabed mobility and the risk of interaction with external hazards such as fishing gear and vessel anchors (Cable Burial Risk Assessment). The burial depth will likely vary across the cable types and routes as a result of these factors.

4.6.6.3 Cable installation can be broadly categorised into three approaches, listed below, though a variation or combination of these approaches may be utilised:

1. Post-lay burial: laying the cable on the seabed prior to installation via pre-lay burial.
2. Simultaneous lay and burial: the cable is buried as it is laid on the seabed.
3. Pre-lay trenching/ploughing: a trench is formed prior to the cable being laid within it.

4.6.6.4 Cable installation techniques include trenching (including pre-trenching, dredging and mechanical cutting), jetting, ploughing, pre-ploughing, vertical injection and Mass/Controlled Flow Excavation (MFE/CFE).

4.6.6.5 Where pre-trenching or rock cutting is employed and there is a gap between this activity and cable installation, the trench may partially collapse, or infill in some areas. In these cases, pre-sweeping may have to be performed to clear the trench prior to installation. Pre-sweeping typically comprises the use of a jetting tool, pre-trenching plough or pre-trenching draghead mounted to a Trailer Suction Hopper Dredger (TSHD) or similar, targeted to remove the material that has partially infilled the trench.

4.6.6.6 In areas where cables cannot be buried, due to crossing third party infrastructure, such as existing cables or pipelines, or obstacles such as exposed bedrock, both the third-party asset and the installed cable must be protected and made secure to maintain the integrity of the cable. This is typically achieved through some form of separation layer, such as a concrete mattress, and protection, such as rock placement (crossings are further described in paragraph 4.6.6.17).

4.6.6.7 Cable installation and route preparation will be undertaken by specialist vessels. Based on previous experience within Ørsted, it is possible that a small jack-up vessel or a flat top barge will be required for cable installation in shallow water near to landfall and that multiple installation vessels may be required to perform cable installation, such as a trench being opened with a first vessel prior to a second vessel pass performing the cable lay and burial. The full vessel requirements for installation of cables are shown in Table 4-21.

4.6.6.8 In the event that cables need to be stored temporarily on the seabed, referred to as 'wet storage', due to vessel availability, inclement weather, awaiting pull-in to structures or otherwise, the maximum temporary area required for each cable type is 1,500 m^2.

4.6.6.9 All offshore cables will be buried up to 5 m. A Cable Burial Risk Assessment (CBRA) will inform and refine burial requirements such as burial depth and depth of cover, dependent on ground conditions as well as external risks. This assessment will be undertaken post-consent.

4.6.6.10 The maximum design parameters for cable installation are presented in Table 4-18.

Table 4-18 Maximum design parameters for offshore cable installation

Parameter	Maximum design parameters			
	Array Cables	*Interlink Cables*	*UK Transmission Cables*	*Offshore Electrical Connection Cable*
Installation Methodology	Surface-lay, trenching (incl. dredging, mechanical cutting), including pre-trenching, with or without post lay backfill, jetting, ploughing/pre-ploughing, vertical injection, mass flow excavation			
Total length	490 km	100 km	125 km (within Offshore Array)	90 km
Cable installation width	15 m			
Seabed disturbance area	7,350,000 m^2	1,500,000 m^2	1,875,000 m^2	1,350,000 m^2
Burial depth; Vertical Injection (Ploughing and MFE)	5 m			
Burial spoil: jetting	22,050,000 m^3	4,500,000 m^3	5,625,000 m^3	4,050,000 m^3
Jetting excavation rate (soft or loose soil)	300 (125) m/hr			
Ploughing excavation rate medium soil (hard soil)	125 (55) m/hr			
Installation duration: total	24 months			

Cable Protection

4.6.6.11 Cable protection will be required where cable burial is not possible, such as cable crossings and areas where sediments are prohibitively stiff, to both cover and stabilise the cable. Up to 15% of the total cable length of all cable types may require some form of protection due to unforeseen ground conditions and tool failure. The different cable protection methods are described in the sections below.

Rock Placement

4.6.6.12 Rocks of various grade sizes are placed over the cable from a fall pipe vessel. Typically, smaller rocks are placed first to provide a protective covering layer from larger rocks placed on top.

4.6.6.13 The rock grading generally has a mean rock size between 90 to 125 mm, up to a maximum of 500 mm where protection from larger anchors is required. Once placed, the rock berm forms a trapezium shape, up to 2.5 m above the seabed with a 3:1 gradient and berm width of 15 m (see Figure 4-5). The berm length depends on the length of cable requiring protection, though is not expected to exceed 800 m. Expected scour may also vary the rock berm design. For crossings, this protection method is used once a separation layer, such as a mattress, is first laid over the asset being crossed.

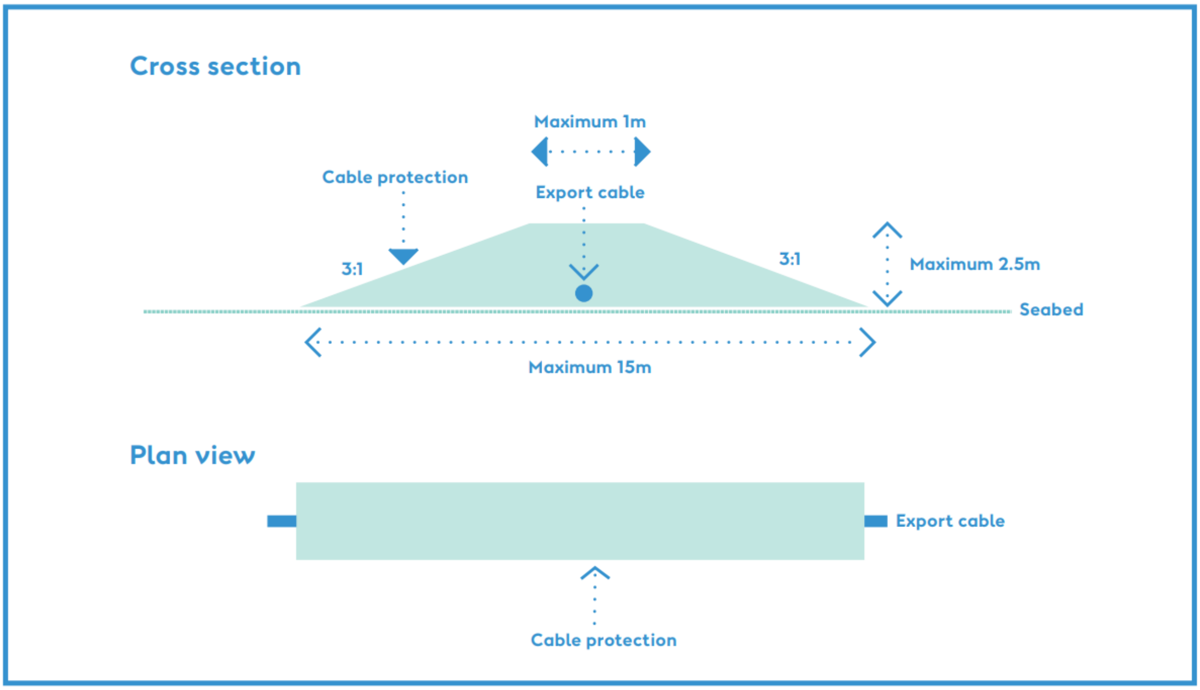

Figure 4-5 Rock placement used as cable protection.

4.6.6.14 Rock placement is also required to stabilise Cable Protection Systems (CPS) installed around cables in the transition zone between the structure foundation and the seabed. The placement of this rock can extend beyond the edge of any scour protection installed around the foundation.

Mattresses

4.6.6.15 Mattresses generally have dimensions of 6 m by 3 m by 0.3 m. They are formed by interweaving concrete blocks with rope and wire. They are lowered to the seabed on a frame. Once positioning over the cable has been confirmed, the frame release mechanism is triggered, and the mattress is deployed. This single mattress placement will be repeated over the length of cable which is either unburied or has not achieved target depth. Mattresses provide protection from direct anchor strikes but are less capable of dealing with anchor drag. Should this protection method be used for crossings, a mattress separation layer may first be laid on the seabed.

Rock bags

4.6.6.16 Rock bags are rocks of various grade sizes contained within a rope or wire mesh containment. They are placed via a crane to the seabed and typically used to stabilise the cable and for trench or scour related issues.

Crossings

4.6.6.17 There are several existing third-party assets within the Mooir Vannin Offshore Array and Offshore ECSA which will require crossing by the Array Cables, Offshore Electrical Connection Cables and UK Transmission Assets. The specific design and methodology for these crossings will be confirmed in a crossing agreement with the asset owners, though typically a pre-lay berm of separation layer will be placed over the existing asset for protection, with the Proposed Development cable then laid across this, at an angle close to 90° to minimise interaction, prior to being covered by a post-lay berm to protect and secure the cable. A typical crossing is illustrated in Figure 4-6.

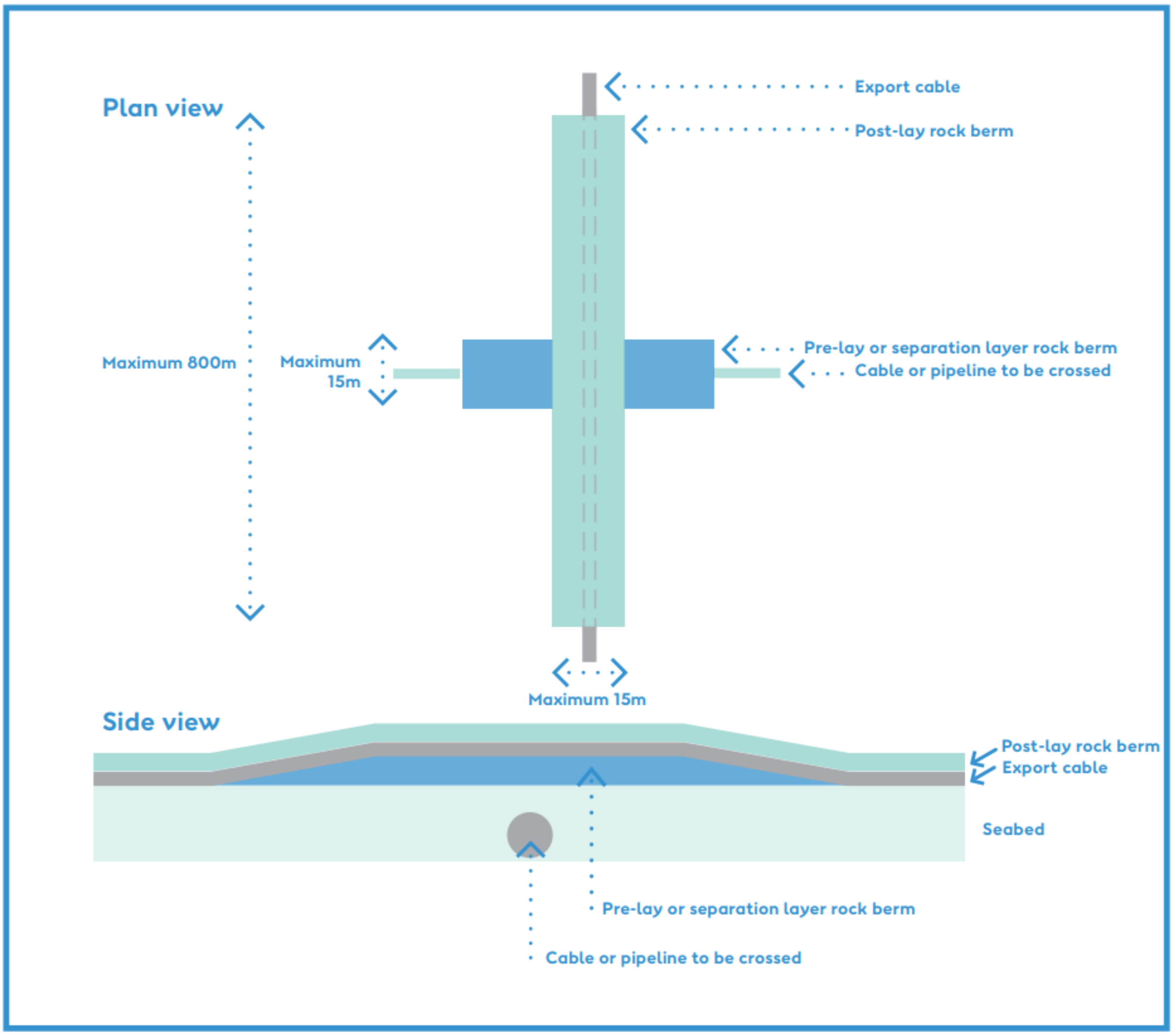

Figure 4-6 Cable crossing with use of separation layer and post-lay rock berm

4.6.6.18 The rock berms will be inspected at regular intervals and may need to be replenished with further rock placement dependent on their condition. This operational rock placement would not exceed 25% of the estimated rock volume and would occur in areas already disturbed by rock placement (i.e., no new areas of disturbance above what is assessed in the 15% of the cable length areas).

4.6.6.19 Where 3rd party cables are confirmed to be redundant, they may also be cut either side of the cable route with the cut section repositioned or removed, and the cable ends secured with clump weights.

Maximum Design Parameters

4.6.6.20 The maximum design parameters for cable protection are presented in Table 4-19.

Table 4-19 Maximum design parameters for cable protection

Parameter	Maximum design parameters			
	Array Cables	*Interlink Cables*	*UK Transmission Cables*	*Offshore Electrical Connection Cable*
% of route requiring protection	15%			
Rock size	0.5 m			
Height of rock berm	2.5 m			
Pre- and post-lay width of rock berm at seabed	15 m			
Pre-lay length of rock berm at seabed	50 m			
Post-lay length of rock berm at seabed	800 m			
Replenishment requiring operation (% of construction total)	25 %			
Rock protection area	1,103,000 m^2	225,000 m^2	281,250 m^2	203,000 m^2
Rock protection volume	1,176,000 m^3	240,000 m^3	300, 000 m^3	216,000 m^3
Number of crossings	3	0	6	6
Crossings: pre- and post-lay rock berm area	35,000 m^2	n/a	279,000 m^2	70,000 m^2
Crossings: pre- and post-lay rock berm volume	39,000 m^3	n/a	314,000 m^3	70,000 m^2

Cable Jointing

4.6.6.21 Cable joints may be required to join lengths of cable together, due to the limited carrying capacity of cable installation vessels. Excavation of a jointing pit with a dredging vessel (or similar) is required to bury and protect the cable joint. Material will be removed to a nearby designated disposal site and recovered for backfilling once the joint is in position. It may be necessary to recover additional material from the licensed dredge/disposal area bordering the ECC, to make up for any lost during the operation due to winnowing of material by hydrodynamic processes.

4.6.6.22 The maximum design parameters for cable jointing are presented in Table 4-20.

Table 4-20 Maximum design parameters for cable jointing

Parameter	Maximum design parameters
Number of offshore cable joints (per cable)	1
Depth of offshore jointing pit	5
Area of offshore jointing pit	3,500 m^2
Volume of offshore jointing pit	17,500 m^3
Material loss during dredge/recover (subject to make-up)	50%

4.7 Vessel activities (construction)

4.7.1.1 The construction of the Proposed Development will require the use of a number and variety of vessels for installation, support and transport of infrastructure and equipment to the Offshore Array and Offshore Electrical Connection Cable corridor, including the use of helicopters for transferring crew and equipment to the site.

4.7.1.2 During construction of the Proposed Development, there can be a total of up to 30 vessels in the Offshore Array area on any given day.

4.7.1.3 The total vessel numbers, vessel movements and durations are presented in Table 4-21. Each vessel movement represents a return trip to and from the Offshore Array.

Table 4-21 Maximum design parameters for vessel and helicopter activities during construction

Vessel	Maximum design parameters	
	Number of vessels	*Number of return trips per vessel type*
WTG installation		
Installation vessel (JUV or anchored)	4	100
Support vessel	24	600
WTG installation support vessels include (with indicative numbers): crew boats (x15), service operation vessels (SOV) (x4), tugs (x4), miscellaneous support vessels (guard vessels) (x3)		
Transport vessel	12	300
Helicopters	2	200
WTG foundation installation		
Installation vessel (JUV or anchored)	4	100
Support vessel	16	400
WTG foundation installation support vessels include (with indicative numbers): tugboats (x10), crew boats (x2), drilling vessels (x2) and guard boats (x2)		
Transport / feeder vessel (including tugs) (of which anchored)	40 (2)	400
Helicopter	1 per day per major vessel	200
Offshore Platform installation		
Installation vessel	2	20
Support vessel	12	120
Transport vessel	4	40
Helicopter (including commissioning works)	2	250
Offshore Platform foundations installation		
Installation vessel	2	4 per Offshore Platform
Support vessel	4 per Offshore Platform	365
Transport vessel	2 per Offshore Platform	4 per Offshore Platform

Helicopter (including commissioning works)	2	10
Offshore Array Cables and Interlink installation		
Main cable laying vessel	3	20
Main cable burial vessel	3	20
Support vessel	12	630
Helicopter (including commissioning works)	2	333
UK Transmission Assets installation		
Main cable laying vessel	3	17
Main cable jointing vessel	3	10
Main cable burial vessel	3	9
Support vessel	15	125
Helicopter (including commissioning works)	2	300
Offshore Electrical Connection Cable installation		
Main cable laying vessel	3	10
Main cable jointing vessel	1	5
Main cable burial vessel	3	5
Support vessel	15	75
Helicopter (including commissioning works)	2	300

4.7.2 Aids to Navigation, lighting and marking

4.7.2.1 All surface infrastructure (including wind turbine generators, offshore substations), including any required aids to navigation, will be designed in accordance with relevant guidance from Trinity House, the CAA and the Maritime and Coastguard Agency (MCA). This will include colours, marking and lighting. The positions of all infrastructure will be conveyed to the UK Hydrographic Office (UKHO) so that they can be incorporated into Admiralty Charts and the Notice to Mariners (NtM) procedures.

4.7.2.2 Lighting and marking of subsea structures will be discussed with the Northern Lighthouse Board (NLB), having a statutory duty as a General Lighthouse Authority, where there may be a risk to shipping. In this case, the marking would be based on the recommendations of the International Association of Marine Aids to Navigation and Lighthouse Authorities (IALA Recommendation O-13, 2021.).

4.7.3 Safety Zones

4.7.3.1 During construction and decommissioning, it is expected that the Applicant will seek a 500 m safety zone around infrastructure that is under construction, including at the Proposed Development's intertidal area. Safety zones of 50 m will be sought for incomplete structures at which construction activity may be temporarily paused (and therefore the 500 m safety zone has lapsed) such as where construction works are completed but the Proposed Development has not yet been commissioned.

4.7.3.2 During the operation and maintenance phase, the Applicant may apply for a 500 m safety zone around manned infrastructure (such as offshore accommodation platform) in order to ensure the safety of the individuals aboard. The Applicant may also apply for 500 m safety zones for infrastructure undergoing major maintenance (for example a blade replacement).

4.7.3.3 Further information regarding the Safety Zones which the Applicant intends to apply for post consent will be outlined in the Safety Zone Statement.

4.7.4 Wave buoys

4.7.4.1 The Proposed Development will require two wave buoys for the full construction period, one of which will be decommissioned following completion of construction, and the other retained for the O&M period, potentially being replaced by a wave radar. The exact mooring locations are currently undefined but will be communicated via a NtM once confirmed.

4.8 Offshore Pre-Construction activities

4.8.1.1 Pre-construction activities include pre-construction surveys to provide a detailed understanding of the ground conditions and subsequent seabed preparation activities that are required to facilitate installation of infrastructure and reduce working risk to as low as reasonably practicable (ALARP) to ensure a safe working environment.

4.8.1.2 The two types of pre-construction surveys are geophysical and geotechnical. Geophysical surveys "scan" the seabed with different instruments to provide a digital representation of the surface and subsurface of the seabed, to inform the project's understanding of the site's bathymetry, ground conditions and identification of targets (objects). Geotechnical investigations involve the physical sampling of the seabed at different depths to further develop the ground model, ground-truth the geophysical surveys and inform potential Horizontal Directional Drilling (HDD) works at the landfall location and the foundation design for WTGs and Offshore Platforms.

4.8.1.3 The purposes of seabed preparation activities carried out prior to installation of infrastructure include but are not limited to, sandwave clearance to level the seabed, boulder clearance to remove obstacles, placement of rock to reinforce the ground, reduce scour or protect an asset for a cable crossing and Pre-Lay Grapnel Run (PLGR) to clear the cable route of debris. These activities will likely take place separately to one another in subsequent campaigns, depending on the order of installation for the offshore assets.

4.8.1.4 The requirements for these activities will be fully informed by high-resolution geophysical surveys undertaken within the Offshore Array and the Offshore Electrical Connection Cable corridor in the post-consent / pre-construction stage. The maximum design parameter for each seabed preparation activity is additionally specific to the asset it is carried out for i.e., seabed clearance is carried out within a corridor for cable installation and within an area for foundation installation. As such, at the current stage for PEI Consultation, a summary of the types of pre-construction activities is outlined in Table 4-22**Error! Reference source not found.** and the maximum design parameters for each scope is presented with a description of the relevant activities in the following sections.

Table 4-22. Maximum Design Scenario: Pre-Construction Activities

Parameters	Design Envelope
Geophysical survey types	Multi-Beam Echo Sounder (MBES), Seabed Imaging Sonar (SIS), Magnetometer (Mag), Sub-bottom Profiler (SBP) and Ultra High Resolution Seismic (UHRS)
Geophysical survey scope	Full coverage of the construction corridors and foundation locations
Geotechnical survey investigations	Boreholes, Cone Penetration Tests
Geotechnical investigation scope	Samples required for each foundation location (WTGs & OSS, up to 105 locations) with 10% contingency locations.
Seabed preparation activities	Boulder clearance (grab and plough), sandwave clearance (Controlled Flow Excavation, Trailing Suction Hopper Dredger), PLGR, rock placement (scour, crossings and cable protection).

4.8.2 Boulder Clearance

4.8.2.1 Where large volumes of boulders are present, micrositing of cables around these areas may be onerous, impractical and in some cases not possible. Boulders left *in situ* may pose risks of obstruction to installation tools and equipment, leading to damage to the equipment or cable itself, or the requirement for multiple passes or post-lay cable protection, all resulting in delays to the cable installation programme.

4.8.2.2 Based on current industry-guidance, boulders greater than 0.3m in any dimension must be cleared from a corridor of up to 40m for all cable types, to ensure the cable burial tools can operate sufficiently.

4.8.2.3 There are two methods used for clearance of boulders, typically dependent on the density of boulders encountered:

- Plough: used for high-density areas of boulders, clears multiple boulders from the path of the plough.
- Subsea grab: used for low-density or larger boulders, picks individual boulders from the route.

4.8.2.4 The maximum design parameters for boulder clearance are presented in Table 4-23.

Table 4-23 Maximum design parameters for boulder clearance

Parameter	Maximum design parameters
Offshore Array	
Cable corridor clearance width per cable (circuit) (all cable types) (plough)	40 m
Cable corridor clearance width per cable (circuit) (all cable types) (grab)	40 m
Clearance area per WTG Foundation	250 m radius
Clearance area per Offshore Platform Foundation	250 x 250 m box
Seabed disturbance area (Array Cables)	19.6 km^2
Seabed disturbance area (Offshore Electrical Connection Cables)	0.96 km^2
Seabed disturbance area (Interlink Cables)	4 km^2
Seabed disturbance area (UK Transmission Assets)	5 km^2
Seabed disturbance area (WTG Foundations)	19.64km^2
Seabed disturbance area (Offshore Platform Foundations)	0.32km^2
Total seabed disturbed in Offshore Array	46.52 km^2
Offshore Electrical Connection Cable corridor	
Cable corridor clearance width per cable (circuit) (plough)	40 m
Cable corridor clearance width per cable (circuit) (grab)	40 m
Length of Offshore Electrical Connection Cable corridor from Offshore Array to landfall	28 km
Total seabed disturbed for Offshore Electrical Connection Cable	3.6 km^2
Total seabed disturbed in Offshore Electrical Connection Cable corridor (outside of Offshore Array)	3.36 km^2

4.8.3 Sandwave Clearance

4.8.3.1 Sandwave clearance may be required in areas within the Offshore Array and the Offshore Electrical Connection Cable corridor, to provide a relatively flat surface for the cable installation tools to operate and to ensure the cable remains buried due to the mobile nature of sandwaves.

4.8.3.2 The maximum design parameters for sandwave clearance are presented in Table 4-24.

Table 4-24 Maximum design parameters for sandwave clearance

Parameter	Maximum design parameters
Offshore Array	
Sandwave clearance impact width per cable (all cable types)	40 m
Sandwave clearance volume (Array Cables)	11,760,000 m^3
Sandwave clearance volume (Interlink Cables)	2,400,000 m^3
Sandwave clearance volume (UK Transmission Assets)	3,000,000 m^3
Sandwave clearance volume (OECC within Offshore Array)	576,000 m^3
Seabed disturbance area (Array Cables)	19.6 km^2
Seabed disturbance area (Interlink Cables)	4 km^2
Seabed disturbance area (UK Transmission Assets)	5 km^2
Total seabed disturbed in Offshore Array	17,737,000 m^3
Offshore Electrical Connection Cable (OECC)	
Seabed disturbance area	3.6 km^2
Sandwave clearance volume (outside of Offshore Array)	2,160,000 m^3

4.8.4 Pre-lay grapnel run

4.8.4.1 Following the pre-construction route survey and boulder clearance works, a Pre-Lay Grapnel Run (PLGR) and an associated route clearance survey of the final cable route will be undertaken. A vessel will be mobilised with a series of grapnels, chains, recovery winch and survey spread suitable for vessel positioning and data logging. Any items recorded will be recovered onto deck where possible and the results of this survey will be used to determine the need for any further clearance. The PLGR work will take account of and adhere to any archaeological protocols developed for the Proposed Development.

4.8.4.2 These works will be within the 40m footprint of seabed disturbance (sandwave and boulder clearance), within which is the 15m footprint for trenching in the Offshore Electrical Connection Cable corridor and therefore any footprint for PLGR disturbance is already accounted for.

4.8.5 Unexploded ordnance inspection and clearance

4.8.5.1 It is not anticipated that unexploded ordnance (UXO) from military testing activities, World War I or World War II will be encountered during construction, due to the Isle of Man's location and other factors considered in a desk-based assessment. Desk-based assessments have concluded that the planned geophysical surveys are anticipated to identify up to approximately 30 potential UXOs which will require further inspection, though will likely not be confirmed as such. UXO's pose a health and safety risk for vessels conducting operations and it is therefore necessary to survey and carefully manage UXO, through avoidance, removal or clearance. Should any be identified following completion of geophysical surveys that require management, the relevant procedures and requirements to allow inspection and clearance work to take place, which are yet to be determined between the Applicant and the Isle of Man Government, will be undertaken.

4.9 Landfall

4.9.1 Overview

4.9.1.1 The Offshore Electrical Connection Cable(s) will make landfall at Groudle Bay and/ or Port Skillion. As such, both landfall locations may be utilised. The preferred landfall location is Port Skillion due to the proximity to the potential Onshore Substation locations.

4.9.1.2 The landfall works required for the Proposed Development include:

- Construction of a landfall compound;
- Installation works (trenchless or open-cut);
- Construction of TJB(s);
- Installation of Offshore Electrical Connection Cable(s);
- Joining of the Offshore and Onshore Cables in the TJB(s);
- Backfilling of Joint Bays; and
- Reinstatement works.

4.9.1.3 The Offshore Electrical Connection Cable(s) will connect to the Terrestrial Connection Cables at TJB(s) situated below MHW or above within a landfall compound. The techniques used to install the Offshore Electrical Connection Cable(s) up to the TJB broadly fall into two categories: trenchless techniques (such as Horizontal Directional Drilling (HDD)) or open cut installation. An intrusive geotechnical survey campaign during pre-construction will determine the technical feasibility of both approaches, which will factor in ground conditions, cable design and other environmental conditions.

4.9.2 Construction

4.9.2.1 The landfall logistics compound is a temporary construction site required onshore (above MHW) to house the TJB works, any HDD plant and equipment, any open cut installation plant and equipment required and any supporting equipment and facilities. The TJBs are pits dug and lined with concrete, in which the jointing of the offshore and onshore export cables takes place. Up to three TJB's will be required, one for each export cable circuit. They are constructed to ensure that the jointing can take place in a clean, dry environment, and to protect the joints once completed. Once the joint is completed the TJBs are covered and the land above reinstated. It is not expected that the TJBs will require access during the operation of the Proposed Development, however link boxes located nearby do require access during the operational phase, which will be reinstated but may have maintenance hole covers for access and fencing to prevent damage.

4.9.2.2 Access points may be required from the public highway to access the landfall locations to carry out the construction and logistics compound works. Temporary access points from the highway will be installed to facilitate vehicular access from the road, and into to the logistics compound and landfall working area during construction.

4.9.2.3 The proposed landfall options are shown in Figure 4-7, with the Landfall Zones indicating the potential location for a temporary landfall logistics compound.

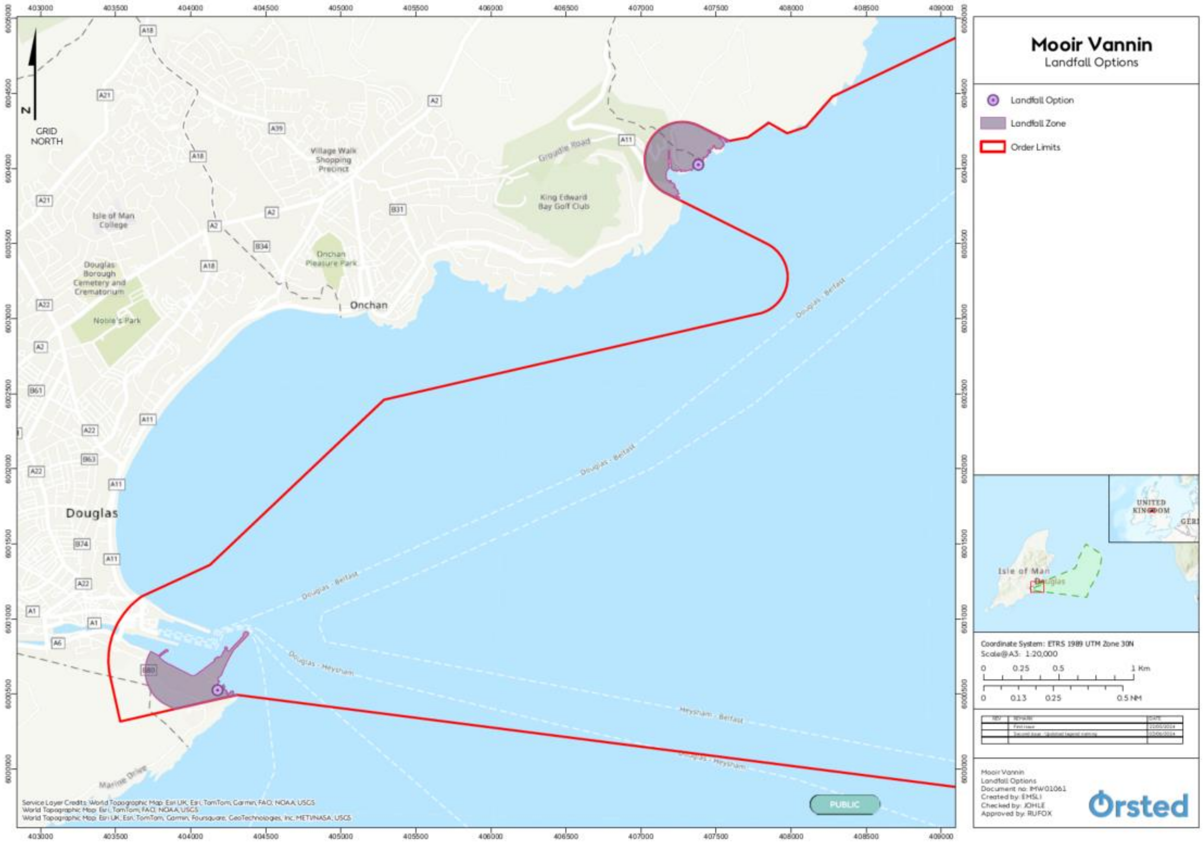

Figure 4-7 Landfall options at Groudle Bay and/ or Port Skillion

4.9.2.4 Due to the nature of the operations carried out during landfall works, certain operations such as the HDD drill or cable pull, must be completed once started due to operational, health and safety reasons. As such, the working hours for the landfall works would be up to 24 hours per day, seven days a week (24h/7d).

4.9.2.5 The maximum design parameters for the landfall construction corridors, TJB(s) and landfall logistics compound is provided in Table 4-25.

4.9.2.6 The durations for the landfall activities demonstrate that certain activities will have a significantly shorter duration than the overall construction window (start to finish). This is largely due to the need to carry out landfall works before and after the Offshore Electrical Connection Cable(s) make landfall, as well as requiring flexibility for these activities to shift within the overall timeframe.

Table 4-25 Maximum design parameters for landfall construction, TJB(s) and temporary logistics compound

Parameter	Maximum design parameters
Temporary construction corridor width	450 m
Permanent construction corridor width	210 m
Temporary construction area above MHW (Port Skillion)	45,000 m^2
Temporary construction area above MHW (Groudle Bay)	35,000 m^2
Permanent construction area above MHW	16,800 m^2
Number of TJBs (allowing for 2 failures)	3 (5)
TJB depth	6 m
Landfall logistics compound area	13,000 m^2
Duration of works for each HDD (trenchless technique)	4 months
Duration of trenching works per cable (open cut)	1 month
Duration of works (start – finish)	36 months
Construction working hours	24h/7d

Trenchless techniques

4.9.2.7 Trenchless techniques such as HDD involve drilling a borehole with a drilling rig in the landfall logistics compound from an entry pit (approximately at the location of the TJB) to an exit pit either above MHW, in the intertidal area or below MLW, thereby avoiding interaction with surface features.

4.9.2.8 For HDD works, the logistics compound will be set up in the following way:

- The required compound will be demarcated using security fencing.
- Topsoil will be removed and stored within the allocated compound areas.
- Stone and tarmac will be imported for final surfacing, followed by site setup works and Porta cabin deliveries.
- Existing access roads may be upgraded, or new access roads may be constructed into the landfall logistics compound.

4.9.2.9 The trenchless technique process uses a drilling head controlled from the rig to drill a pilot hole from the entry pit along a predetermined profile to the exit pit. This pilot hole is then widened using larger drilling heads and drilling mud pumped to the drilling head during the drilling process to stabilise the bore and ensure that it does not collapse. Once the bore is at the required width, a duct is pulled back through the bore by the HDD rig or by separate winches, through which the Offshore Electrical Connection Cables are then pulled and installed. These ducts are either constructed offsite, then sealed and transported to the site, or will be constructed within the landfall logistics compound and transported into the required position for installation.

4.9.2.10 The general HDD process is illustrated in Figure 4-8.

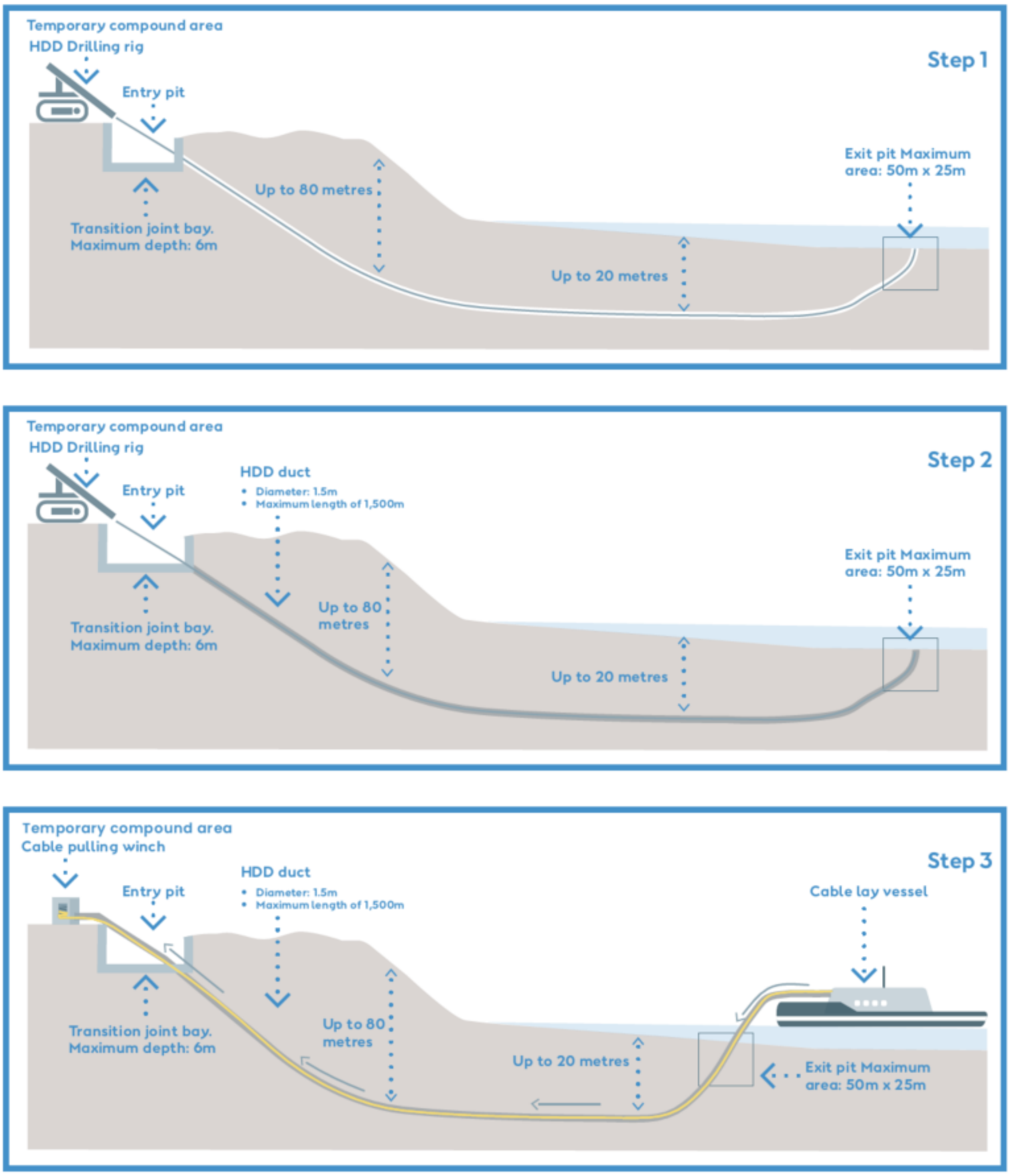

Figure 4-8 General process for HDD works

4.9.2.11 As the drill is carried out between a start and end point, a pit must be dug at both ends of each planned drill to below the level required for the cable, so the drilling rig can carry out the drill horizontally, and the ducts can be installed. Depending upon the final methodology and location of the exit pits, it may be necessary to consider dewatering (pumping dry) and water exclusion (e.g., cofferdams). Measures for management and containment of drilling slurry will need to be implemented at the exit pit, and these may comprise the use of a mud return line to recover and recycle fluid from the punch out location. The detailed landfall construction methodology will be defined once further site-specific surveys and feasibility studies have been conducted.

4.9.2.12 Once the ducts have been installed, the pits will likely be temporarily back filled until the time for cable pull-in. The ducts will then need to be re-exposed (dredged) (no coffer dams are necessary for this operation) to pull in the cables. If material is removed by barge to a designated disposal site, before being recovered for backfilling, excavated material will need to be re-imported from the storage area. Some additional material (e.g., rocks) may be necessary to make up for any loss, or in case the onward plough cannot bury the cable within the exit pit.

4.9.2.13 The maximum duration for landfall works is 6 months, within a 36-month period. Individual HDD operations, including site setup and reinstatement, may take up to 4 months per drill, as up to two pits could be open at one time.

4.9.2.14 Wherever possible, access will be maintained across the beach and public diversions established. Where Public Right of Ways (PRoWs) are required to be closed during the construction of the landfall works, their closure will be limited only to allow construction works to complete. Where closures are required for longer periods, the relevant authority will be informed in writing.

4.9.2.15 The maximum design parameters for trenchless techniques (such as HDD) are presented in Table 4-26.

Table 4-26 Maximum design parameters for trenchless techniques

Parameter	Maximum design parameters
Number of HDD ducts	5
Diameter of ducts	1.5 m
Length of ducts	1,500 m
Number of entry and exit pits	10 (5 each)
Entry pit area	16 m^2
Entry pit depth	6 m
HDD burial depth (maximum) (along Offshore Export Connection Cable corridor)	80 m (20m)
HDD burial depth (minimum)	5 m
Exit pit area	1,250 m^2 (50m x 25 m)
Exit pit excavated material volume	6,250 m^3
Exit pits depth	5 m
Temporary onshore/intertidal exit pit working area	10,000 m^2
HDD operational noise	120 dB
Installation duration	6 months (4 months per HDD with overlap)

Open cut

4.9.2.16 Open cut installation would be carried out using one of several methods. Installation tools, such as ploughs, rock cutters or jetting tools, similar to those used offshore, can be pulled from the offshore installation vessel, or from winches within the landfall logistics compound, over a pre-laid cable to simultaneously open a trench, place the cable in the trench, and backfill the cable. Alternatively, the trenching tool may open a trench in advance, the cable would be lowered into this trench and covered, after it has been pulled across the beach. These tools are usually pulled along the beach on skids or are tracked. All the installation techniques described for the Offshore Electrical Connection Cable installation are applicable to the landfall installation.

4.9.2.17 As with the trenchless technique, a landfall logistics compound will be established up to one month before installation. This would include plant storage, consumable storage area including fuel, welfare facilities, parking, pulling winches, anchor points and TJB. In addition, whilst works are ongoing on the beach, a temporary closure or diversion may be required from MLW to the landfall logistics compound for operational, and health and safety reasons. This would be up to one month per cable.

4.9.2.18 Prior to the vessel arrival, rollers may be placed from MLW to the plough grade in position, if a plough is used. Upon vessel arrival, the plough is landed and pulled back to the grade in position. Tugs may be required for anchor placement. This would take approximately two days. Rollers would be placed between the plough and the vessel. The Offshore Electrical Connection Cable would be pulled from the vessel, through the plough to the TJB in the duration of one day.

4.9.2.19 Rollers would then be removed, and the cable would be laid on the beach. Burial works would then commence, with excavators entering the intertidal area to excavate a trench next to the cable, after which the cable would be lowered into the trench. Mattresses (or similar) may be placed over the cable. The trench is then reinstated followed by the removal and reinstatement of the landfall logistics compound.

4.9.2.20 These works may also be undertaken by self-powered vehicles that are either controlled from onboard the vehicles themselves or are Remotely Operation Vehicle (ROV) type systems.

4.9.2.21 The maximum design parameters for open cut installation are presented in Table 4-27.

Table 4-27 Maximum design parameters for open cut installation

Parameter	Maximum design parameters
Distance between circuits	30 m
Burial depth	5 m
Excavation progress rates	50 m/day
Corridor width per circuit	30 m
Potential disturbance corridor from plant movements, excavation, etc. (per cable)	60 m
Construction working hours	24h/7d

4.10 Construction Programme

4.10.1.1 The indicative high-level construction programme for the Proposed Development is presented in Figure 4-9. The programme illustrates two periods for each activity: the likely duration of the installation works and the window in which that installation may occur. Key milestones for the Proposed Development are also shown. Activities may not be continuous, and the sequence of activities may change. The detailed construction programme will be developed as design and procurement activities progress.

4.10.1.2 The indicative start of construction for the Proposed Development commences with the landfall works which may start as early as Q4 2030.

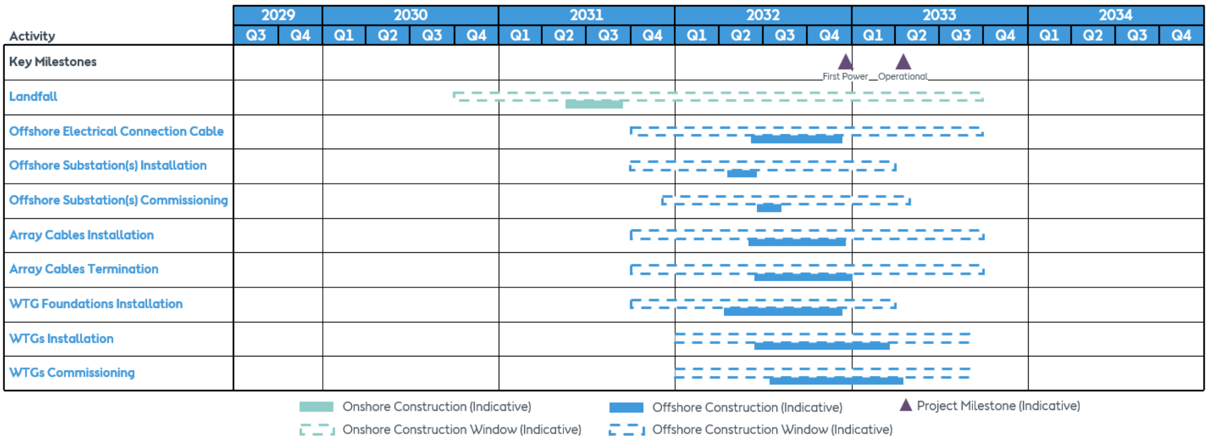

Figure 4-9 Indicative Construction Programme

4.11 Operations, Maintenance and Decommissioning

4.11.1.1 This section provides a description of the reasonably foreseeable operation, maintenance and decommissioning activities for the Proposed Development. Only these activities form part of the Proposed Development, not the physical facilities (O&M Base), which are subject to a separate Isle of Man and/ or UK consent under the relevant planning legislation and regulations (if an existing facility is not utilised).

4.11.1.2 The Operations and Maintenance (O&M) phase will commence once the Proposed Development has completed construction and is fully commissioned. The operational lifetime of the Proposed Development is expected to be up to 35 years, with a possible extension by repowering the site depending on the condition of the infrastructure. At the end of the operational lifetime, it is anticipated that all structures above the seabed or ground level will be completely removed as part of the decommissioning sequence over approximately three years, further described in 4.11.3.

4.11.1.3 An O&M Plan shall be developed for the Proposed Development post-consent, informed by this Project Description and once the O&M Base and technical specification of the Proposed Development are known. The strategy will require an O&M base onshore and/or offshore and will rely on Crew Transfer Vessels, Service Operation Vessels, offshore accommodation, supply vessels and helicopters for the O&M services that will be performed at the windfarm. The strategy will describe the extent and type of maintenance activities, which can be broadly separated into two categories:

- Preventive maintenance: undertaken in accordance with a planned and routine schedule and will include activities such as inspections.
- Corrective maintenance: typically reactive and carried out as a repair, replacement or retrofit campaign. Unmanned, remotely operated or autonomous vessels may also be used for inspections.

4.11.1.4 Two scenarios for personnel visits options are currently envisaged to inform the MDS for O&M activities, either:

- Scenario [A]: O&M from an onshore helicopter base; or
- Scenario [B]: O&M from an offshore base or vessel with helicopter personnel transfer.

4.11.1.5 The maximum design parameters for offshore O&M activities and the total operational vessel and helicopter trip requirements for both scenarios are shown in Table 4-28, with a single visit comprising a return trip to and from the Offshore Array area.

Table 4-28 Maximum design parameters for offshore O&M activities and the total operational vessel and helicopter trip requirements for Scenarios [A] and [B].

Parameter	Maximum design parameters
Offshore O&M requirements	
Number of Crew Transfer Vessels (CTVs)	6
Number of Service Operation Vessels (SOVs)	2
Number of Jack Up Vessels (JUVs)	Ad hoc
Number of supply vessels	Ad hoc
Helicopter capacity	15
Operational hours	24h/7d
Total operational vessel and helicopter requirements	
WTG visits (included in Scenario [A] only) (per year)	1,433/y
WTG foundation visits (included in Scenarios [A] and [B]) (per year)	433/y
Offshore Platform visits - Structural Scope (included in Scenarios [A] and [B]) (per year)	39/y
Offshore Platform visits - Electrical Scope (included in Scenarios [A] and [B]) (per year)	60/y
Crew shift transfers (included in Scenarios [B] only) (per year)	260/y
Total trips (MDS of Scenarios [A] or [B]) (per year)	1,966/y
Jack-up WTG visits (per year)	20/y
Jack-up foundation visits (per year)	46/y
Jack-up Offshore Platform visits - Structural (per year)	3/y
Jack-up Offshore Platform visits - Electrical (per year)	1/y
Jack-up total trips (per year)	69/y
Crew vessels WTG visits (per year)	792/y
Supply vessels accommodation platform visits (per year)	1,040/y

4.11.2 Operation and Maintenance activities

4.11.2.1 This section describes the operation and maintenance activities carried out by the personnel, vessels and helicopters in the prior sections. This includes regular and scheduled activities as well as unscheduled reactive maintenance that is likely to occur i.e., the types of faults that offshore wind farms typically experience, based on the Applicant's experience in operating offshore wind farms.

4.11.2.2 Maintenance due to failures that cannot be anticipated are not described here and are therefore not included within the Proposed Development for consent.

4.11.2.3 During the operational life of the Proposed Development (anticipated 35 years), there can be a total of up to 16 vessels in the Offshore Array area on any given day.

4.11.2.4 Descriptions of offshore operation and maintenance activities with the maximum design parameters are provided in Table 4-29.

Table 4-29 Maximum design parameters of offshore operation and maintenance activities

Activity	Rationale	Parameter	Maximum design parameters
Seabed surveys	Seabed surveys will be required to ensure that cables remain buried and that the scour protection around foundations and cable crossings remains intact. Typically, this will be undertaken more frequently in early years, hence the assessment is based on twice yearly for first three years; followed by yearly thereafter.	Number of surveys (lifetime)	38
WTG activities			
Component replacement	This activity allows for the replacement of major wind turbine components, for example blades, blade bearings, hub generators, yaw rings or nacelles (like-for-like or as within the project envelope). Works conducted under this activity would likely require a JUV supported by at least one CTV. There would be up to seven visits on average for exchange events per turbine over the Proposed Development's lifetime.	Number of exchange events (lifetime)	700
		Footprint of seabed disturbance per event – JUV, Anchors	1,536 m^2, 800 m^2
Painting of transition pieces and/ or jackets	This activity includes the application of paint or other coatings to protect from corrosion (internal/external). Technicians and equipment/ large hand tools - will be deployed from a CTV or similar vessel. Surface preparation is required to break down existing surface coatings and any associated corrosion. There will be one full paint job per turbine every 10 years, and one touch-up paint job per turbine every three years.	Number of full painting events (lifetime)	350
Marine growth/ bird waste removal	Marine growth and bird waste will be physically brushed off turbines by hand, using a brush to break down the marine growth/organic waste (where required) followed by high-pressure jet wash (sea water only). Technicians and equipment will be deployed from a CTV or similar vessel. Up to five cleaning events per turbine per year are planned.	Number of cleaning events (lifetime)	17,500
Access ladder replacement	This includes the replacement of access ladders to wind turbine transition pieces or foundations due to damage or corrosion. Access ladder replacement is likely to require a CTV or small JUV. Technicians and equipment will be deployed from a CTV or similar vessel. One ladder replacement event is planned per turbine every five years.	Number of ladder replacement events (lifetime)	700
		Footprint of seabed disturbance per event	1,536 m^2

Activity	Rationale	Parameter	Maximum design parameters
Foundation anode replacement	This includes the removal and replacement of anodes, which are required for corrosion protection (internal and external to the foundation). These sacrificial anodes, usually zinc, are fastened to an external structure. The metal erodes away preferentially and so protects the erosion of the turbine (foundation) steel. Anode replacement works are likely to be undertaken via divers from a dive support vessel. One turbine anode replacement event is planned per turbine every five years.	Number of anode replacement events (lifetime)	700
		Footprint of seabed disturbance per event	800 m^2
J-tube repair/ replacement	The turbine foundation J-tubes occasionally require modifications or corrective maintenance, including alterations to the bell mouth of the J-tubes during a cable repair or replacement (e.g., cutting, re-welding). This work will be undertaken either by divers from a dive support vessel or using a jack-up barge. It is expected that the frequency will be two J-tubes over the lifetime of the Offshore substation	Number of WTG foundation J-tube replacement events (lifetime)	200
		Footprint of seabed disturbance per event	1,536 m^2
Array Cables			
Cable remedial burial	This activity provides remedial burial of array cables that may have become exposed via natural sediment transport processes. As-laid cable data will be reviewed to identify priority areas possibly requiring remediation. A multibeam sonar (or similar) will then be used to confirm the exact location and current cable burial depth and/or areas of exposure. Should any areas of exposed or insufficiently buried cables be identified, jetting equipment (i.e., MFE or similar) operated from a vessel, or diver operated injector, will be powered up and manoeuvred along the exposed cable at a steady rate until the desired burial depth is achieved. Once complete, a seabed survey will be conducted to determine the success of the operation. If necessary, another pass may be required to achieve the specified depth. As-buried data will be documented and only once all remedial works have been agreed will the vessel and associated equipment transit from the field to port for demobilisation.	Lifetime quantity (length) of cable	35 km
		Length of cable subject to jetting (remediation re-burial) per event	2000 m
		Width of disturbed seabed per event	100 m
		Footprint of (temporary) seabed disturbance per event	200,000 m^2

Activity	Rationale	Parameter	Maximum design parameters
Cable protection replacement	Where rock protection has been employed during the construction phase, this may be replenished during operation.	Up to 25% of the volume of cable protection presented in Table 4-19 will be replenished.	
Array cable repairs	Failure of a cable system would be detected by the wind farm protection system. A cable fault would require location testing whilst off load using remote diagnostic techniques from the offshore substation or elsewhere onshore to identify the precise location of any fault along the cable length. Where a fault is detected, it may be necessary to expose the cable prior to recovery where testing will be conducted to establish the extent and type of repair required. The maximum design scenario (in terms of potential environmental impact) for the Proposed Development has been calculated based on full de-burial always being required. Upon completion of re-burial, a post-burial survey will be carried out to assess whether the cable is at the correct position and required burial depth. During all the works, an advisory exclusion zone of 50 m around the cable and 500 m around all vessels involved in the works will be notified via Notice to Mariners.	Number of array cable repairs (lifetime)	6
		Cable trench width	10 m
		Length of cable repair per event	5000 m
		Footprint of seabed disturbance per event	500,000 m2
		Predicted duration of each cable repair event	3 months
		Footprint of seabed disturbance via jacking-up activities for single cable repair event	800 m^2
		Rock-berm area	284,000 m^2
		Rock-berm volume	304,000 m^3
Offshore Platform activities			
Offshore Substation component replacement	This includes the replacement of major components, for example transformers (like-for like or as within consented envelope). These works would likely require a JUV supported by at least one CTV. It is expected that three major components will require replacement per offshore substation over the lifetime.	Number of exchange events (lifetime)	12
		Footprint of seabed disturbance per event	1,536 m^2
Offshore Platform foundation painting	This includes the application of paint or other coatings to protect the offshore substation and accommodation platform foundations from corrosion (internal/external). Technicians and equipment will be deployed from a helicopter, SOV, CTV or similar vessel. Surface preparation is required to break down existing surface coatings and any associated corrosion.	Number of painting events (lifetime)	6
Marine growth/ bird waste removal	As per WTG description	Number of cleaning events (lifetime)	1,050

Activity	Rationale	Parameter	Maximum design parameters
Access ladder replacement	As per WTG description	Number of ladder replacement events (lifetime)	42
Foundation anode replacement	As per WTG description	Number of anode replacement events (lifetime)	42
		Footprint of seabed disturbance per event	800 m^2
J-tube repair/ replacement	As per WTG description	Number of WTG foundation J-tube replacement events (lifetime)	12
		Footprint of seabed disturbance per event	1,536 m^2
Offshore Electrical Connection Cable activities			
Cable remedial burial	As per Array Cables description	Lifetime quantity (length) of cable	2 km
		Length of cable subject to jetting (remediation re-burial) per event	2,000 m
		Width of disturbed seabed per event	100 m
		Footprint of (temporary) seabed disturbance per event	200,000 m^2
Cable protection replacement	As per Array Cables description	Up to 25% of the volume of cable protection presented in Table 4-19 will be replenished.	
Cable repairs	As per Array Cables description	Number of cable repairs (lifetime)	5
		Cable trench width	10 m
		Length of cable repair per event	2,500 m^2
		Footprint of seabed disturbance per event	500,000 m^2
		Predicted duration of each cable repair event	3 months
		Footprint of seabed disturbance via	1,536 m^2

Activity	Rationale	Parameter	Maximum design parameters
		jacking-up activities for single cable repair event	
		Rock-berm area	68,000 m^2
		Rock-berm volume	74,000 m^2
Interlink Cable activities			
Cable remedial burial	As per Array Cables description	Lifetime quantity (length) of cable	7 km
		Length of cable subject to jetting (remediation re-burial) per event	2,000 m
		Width of disturbed seabed per event	100 m
		Footprint of (temporary) seabed disturbance per event	200,000 m^2
Cable protection replacement	As per Array Cables description	Up to 25% of the volume of cable protection presented in Table 4-19 will be replenished.	
Cable repairs	As per Array Cables description	Number of cable repairs (lifetime)	6
		Cable trench width	10 m
		Length of cable repair per event	2,500 m^2
		Footprint of seabed disturbance per event	500,000 m^2
		Predicted duration of each cable repair event	3 months
		Footprint of seabed disturbance via jacking-up activities for single cable repair event	1,536 m^2
		Rock-berm area	56,000 m^2
		Rock-berm volume	60,000 m^3

Activity	Rationale	Parameter	Maximum design parameters
UK Transmission Assets (within Offshore Array)			
Cable remedial burial	As per Array Cables description	Lifetime quantity (length) of cable	3 km
		Length of cable subject to jetting (remediation re-burial) per event	2,000 m
		Width of disturbed seabed per event	100 m
		Footprint of (temporary) seabed disturbance per event	200,000 m^2
Cable protection replacement	As per Array Cables description	Up to 25% of the volume of cable protection presented in Table 4-19 will be replenished.	
Cable repairs	As per Array Cables description	Number of cable repairs (lifetime)	6
		Cable trench width	10 m
		Length of cable repair per event	2,500 m^2
		Footprint of seabed disturbance per event	200,000 m^2
		Predicted duration of each cable repair event	3 months
		Footprint of seabed disturbance via jacking-up activities for single cable repair event	1,536 m^2
		Rock-berm area	56,000 m^2
		Rock-berm volume	60,000 m^3

4.11.3 Decommissioning

4.11.3.1 At the end of the operational lifetime of the Proposed Development, it is anticipated that all structures above the seabed or ground level will be completely removed as part of the decommissioning sequence over approximately three years.

4.11.3.2 Decommissioning will generally be the reverse of the construction sequence, involving similar types and numbers of vessels and equipment. Therefore, the area of seabed impacted during the removal of infrastructure could be the same as the area impacted during its installation. Likewise, it can be assumed the maximum vessel and helicopter parameters presented for installation will apply for decommissioning.

4.11.3.3 The decommissioning plan and programme will be developed prior to construction and be updated during the project's lifespan to take account of changing best-practice and new technologies, in consultation with the Isle of Man Government. The base case assumption is that foundations below a certain seabed depth, all electrical cables, scour and cable protection will be left *in-situ* to minimise environmental impacts associated with their removal.

WTGs and Offshore Platforms

4.11.3.4 WTGs will be removed by reversing the methods used to install them. Piled foundations would likely be cut approximately 1 m below the seabed, with due consideration made of likely changes in seabed level and removed. This could be achieved by inserting a pile cutting devices. Once the piles are cut, the foundations could be lifted and removed from the site. At this point in time, it is not thought to be reasonably practicable to remove entire piles from the seabed, but endeavours will be made to ensure that the sections of pile that remain in the seabed are fully buried.

4.11.3.5 The offshore substations will most likely be a reverse installation where the decommissioning will most likely be in two phases, firstly the topside will be lifted from the foundation to a transport vessel/barge and sailed to a suitable harbour for decommissioning. In the second phase the foundation will be decommissioned; if piled they will be decommissioned as described above.

Offshore Cables

4.11.3.6 Although it is expected that most array and export cables will be left in situ, for the purposes of informing the maximum design scenario for this application for Marine Infrastructure Consent, it has been assumed that all cables will be removed during decommissioning, though any cable protection installed will be left *in situ*. Any exposed cables are more likely to be removed to ensure they do not become hazards to other users of the seabed.

4.11.3.7 It is likely that equipment similar to that which is used to install the cables could be used to reverse the burial process and expose them. Once exposed, a grapnel would be used to pull the cables onto the decks of cable removal vessels. The cables would be cut into manageable lengths and returned to shore. Once onshore, it is likely that the cables would be deconstructed to recover and recycle the copper and/or aluminium and steel within them.

Landfall

4.11.3.8 To minimise the environmental disturbance during wind farm decommissioning the preferred option is to leave cables buried in place in the ground with the cable ends cut, sealed and securely buried as a precautionary measure. Alternatively, partial removal of the cable may be achieved by pulling the cables back out of the ducts. This may be preferred to recover and recycle the copper and/or aluminium and steel within them.

5 Commitments

5.1 Commitments

5.1.1.1 In accordance with adopting a proportionate approach to the EIA process (see Chapter 5, EIA Methodology, Chapter will be made available at Application), the Applicant has further assessed the potential impacts associated with the Proposed Development (see Annex 5.B Impacts Register) and considered mitigation measures (referred to herein as Commitments) that may be adopted to reduce or eliminate those where Likely Significant Effects (LSE) are concluded (see section 1.5.5 of Chapter 5, EIA Methodology, Chapter will be made available at Application).

5.1.1.2 Commitments are classified into primary, secondary and tertiary commitments. Primary Commitments are those that form an intrinsic part of the design, Secondary Commitments are measures that require further activity in order to achieve the anticipated outcome and tertiary commitments are required regardless of the EIA process as they are imposed.

5.1.1.3 The commitments made at the PEI stage are presented in Annex 3.A, Commitments Register. The Primary Commitments to reduce or eliminate LSE at this PEI stage are presented in Table 5-1.

Table 5-1 Primary Commitments at PEI Consultation

Commitment ID	Stage	Commitment type	Commitment	Rationale
Co3	Scoping	Primary	Cable burial will be the preferred method of cable protection, however where burial is not possible, requirements for additional cable protection will be determined through consultation with the relevant stakeholder.	To ensure project infrastructure is sufficiently protected from exposure, and to limit the effects of Electro-Magnetic Fields (EMF) on sensitive ecological receptors.
Co12	RPSS	Primary	Designated heritage assets will be avoided by the careful routing of the onshore infrastructure around sensitive locations.	To avoid impacts to heritage assets of high significance.
Co20	RPSS	Primary	Avoidance, where possible, of identified areas of contaminated land, sensitive areas, carbon-rich land and designated areas onshore.	To minimise the impacts of the onshore infrastructure on areas sensitive to the hydrological environment.
Co45	Scoping	Primary	Minimum blade tip clearance of at least 30 m above LAT.	To minimise the risk of blade allision particularly for sailing vessels with a mast.
Co46	Scoping	Primary	Burial of onshore cable joint bays, with the land above re-instated to former use, except in the instance of link box chambers where access will be required from ground level.	To minimise land take while ensuring access at ground level can be maintained.

6 References

Isle of Man Government (2016), 'Marine Infrastructure Management Act 2016'.

Isle of Man Government (1999), 'Town and Country Planning Act 1999'.

IEMA (2017), 'Delivering Proportionate EIA - A Collaborative Strategy for Enhancing UK Environmental Impact Assessment Practice', IEMA Lincoln.