Bowdun Offshore Wind Farm, Offshore EIA Report

Volume 1, Chapter 3: Project Description

TWP-BOW-RPS-OFE-RPT-00004 | April 2026

Contents

List of Tables

List of Figures

Glossary

Defined Term	Definition
Additional Mitigation	Also referred to as secondary mitigation which is defined by The Institute of Sustainability and Environmental Professionals (ISEP) (formerly Institute of Environmental Management and Assessment (IEMA)) as: Actions that will require further activity in order to achieve the anticipated outcome. These may be imposed as part of the planning consent, or through inclusion in the EIA Report (sic).
Air Gap	The distance between the sea surface and the blade tip. This can be measured from Highest Astronomical Tide (HAT), Lowest Astronomical Tide (LAT) and Mean High Water Springs (MHWS). Regardless of parameter used, conversion factors are applied to ensure the distance will always be the same. Air gap is an important parameter in Collision Risk Modelling (CRM).
Applicant (the)	Bowdun Offshore Wind Farm Limited (BOWFL).
Array Area	The Array Area is the area in which the Offshore Generation Assets will be located.
Bowdun Offshore Wind Farm Limited (BOWFL)	A Special-Purpose Vehicle (SPV) (legal entity) for the purpose of developing the Project. BOWFL are the Applicant for the Offshore Application.
Crown Estate Scotland (CES)	Public corporation accountable to Scottish Government, responsible for the management of land and property, including marine assets in Scotland owned by the monarch.
Effect	Term used to express the consequence of an impact (i.e. the result of change or changes on specific environmental resources or receptors). The significance of an effect is determined by correlating the magnitude of the impact with the importance, or sensitivity of the receptor or resource in accordance with defined significance criteria.
Embedded Mitigation	Measures that are adopted as part of the Proposed Development and therefore assessed within the EIA. The proposed approach for the EIA for the Proposed Development is that Embedded Mitigation includes both primary mitigation and tertiary mitigation. These are defined by the ISEP as follows: Primary: Modifications to the location or design of the development made during the pre-application phase that are an inherent part of the project, and do not require additional action to be taken. Tertiary: Actions that would occur with or without input from the EIA feeding into the design process. These include actions that will be undertaken to meet other existing legislative requirements, or actions that are considered to be standard practices used to manage commonly occurring environmental effects.
Environmental Impact Assessment (EIA)	Process for the assessment of likely significant environmental effects of a project on the physical, biological and human environment during construction, Operation and Maintenance (O&M) and decommissioning.

Defined Term	Definition
Environmental Impact Assessment Regulations (EIA Regulations)	Terminology used in this Offshore EIA Report to refer to three sets of regulations: • The Electricity Works (Environmental Impact Assessment) (Scotland) Regulations 2017; • The Marine Works (Environmental Impact Assessment) (Scotland) Regulations 2017; and • The Marine Works (Environmental Impact Assessment) Regulations 2007.
Export Cable Corridor	The area seaward of MHWS which connects the Array Area with the Landfall within which the Offshore Export Cables will be installed.
High Voltage Alternating Current (HVAC)	A system of power transmission and distribution that utilises alternating current at voltages typically exceeding 1000 volts, as defined by the International Electrotechnical Commission (2015). HVAC systems are designed to efficiently deliver electricity over long distances with minimal losses, leveraging transformers to modify voltage levels.
Impact	A change caused by an action that occurs during a project's lifetime.
Inter-Array Cables (IAC)	Cables which link the Wind Turbines to each other and with the Offshore Substation Platforms (OSPs).
Interconnector Cables	Cables which will connect individual OSPs to each other to provide redundancy against cable failure elsewhere.
Intertidal Area	The area between MHWS and Mean Low Water Springs (MLWS).
J-tube	Curved steel tubes (shaped like a "J") built into fixed offshore Wind Turbine foundations to guide and protect subsea power cables as they enter the structure. They provide a controlled bend radius, shield cables from mechanical damage, and allow safe pull-in from the seabed up into the turbine transition piece or platform. Commonly used on monopiles and jackets.
Landfall	The area in which the Offshore Export Cables make landfall and is also the transitional area between the Offshore Transmission Assets and the Onshore Transmission Assets. Located in the Intertidal Area at Benholm.
Marine Directorate (MD)	The Marine Directorate of the Scottish Government, formerly known as Marine Scotland. The planning and licensing authority for Scotland's seas and custodian of Scotland's National Marine Plan (NMP). The Marine Directorate - Licensing and Operations Team (MD-LOT) are specifically responsible for managing Section 36 Consent and Marine Licence Applications seaward of MHWS.
Maximum Design Scenario (MDS)	The scenario within the design envelope likely to result in the greatest impact on a particular topic receptor, and therefore the one that should be assessed for that topic receptor.
Mean High Water Springs (MHWS)	The average tidal height throughout the year of two successive high waters during those periods of 24 hours when the range of the tide is at its greatest.
Mean Low Water Springs (MLWS)	The average tidal height throughout the year of two successive low waters during those periods of 24 hours when the range of the tide is at its greatest.

Defined Term	Definition
Mitigation	Measures to avoid, prevent, reduce or control effects on the environment. See also definitions for Embedded Mitigation and Additional Mitigation.
National Grid	The national electricity transmission network.
Offshore Application	Term used to refer to the applications associated with the Proposed Development. The Applicant will apply for: • A Section 36 Consent under the Electricity Act 1989; and • Marine Licence(s) under Marine Scotland Act 2010 and Marine and Coastal Access Act 2009.
Offshore Environmental Impact Assessment (EIA) Report (hereafter, 'Offshore EIA Report')	Document prepared to report the findings of the EIA for the Proposed Development and produced in accordance with the EIA Regulations. The Offshore EIA Report is submitted to support the Offshore Application for the Proposed Development, and to comply with EIA Regulations.
Offshore Export Cables	Subsea cables used to transmit electricity generated offshore by the Wind Turbines from the OSPs to shore. The Transition Joint Bay (TJB) is the location where the Offshore Export Cables terminate, and the onshore cabling begins.
Offshore Generation Assets	The infrastructure of the Proposed Development required to generate electricity comprising of the Wind Turbines, Wind Turbine foundations and associated infrastructure e.g. IACs.
Offshore Infrastructure	All of the Offshore Infrastructure associated with the Proposed Development that is located seaward of MHWS, comprising the Offshore Generation Assets and the Offshore Transmission Assets.
Offshore Scoping Report	The report that presents the findings of the EIA scoping process undertaken for the Proposed Development with the purpose of obtaining a Scoping Opinion. The Offshore Scoping Report defines what is intended to be assessed and reported as part of the EIA.
Offshore Substation Platform(s) (OSPs)	OSPs comprise the support structure, topside and electrical components used for collecting and/or converting electricity generated by the Wind Turbines for transmission by the Offshore Export Cables.
Offshore Transmission Assets	The infrastructure of the Proposed Development required to transmit the generated electricity comprising of the OSPs, Offshore Export Cables and associated infrastructure up to MHWS.
Onshore Transmission Assets	The transmission infrastructure associated with the Project above MLWS which is subject to the Planning Permission in Principle (PPP) Application submitted to Aberdeenshire Council (REF: APP/2025/1952).
Operation and Maintenance (O&M)	The phase of the Proposed Development following completion of construction. This phase of development includes routine inspections, repairs and replacement of infrastructure and equipment (including Interconnector Cables and IACs), Scour Protection replenishment or replacement, major component replacement, painting and/or other coating works, removal of marine growth, and replacement of access ladders.
Option to Lease Agreement (OLA)	An agreement between CES and a developer, permitting the future development of offshore wind within an agreed area.

Defined Term	Definition
Piling	The action of installing piles: installation can use various methodologies, the most common of which are impact piling (in which the piles are struck by a "hammer") and drilling (during which a hole is drilled into the seafloor, the drilling tool is removed, and the pile is slotted into that hole).
Plan Option Area (POA)	A location identified in the Sectoral Marine Plan (SMP) as a preferred area for commercial scale offshore wind development.
Project (the)	An overarching term for the Bowdun Offshore Wind Farm (Bowdun OWF) comprising the offshore and onshore infrastructure required to generate and transmit electricity from the Array Area to the onshore GCP. The Project includes the Offshore Generation Assets, the Offshore Transmission Assets and the Onshore Transmission Assets.
Project Design Envelope (PDE)	A description of the range of possible elements that make up the design options for the Proposed Development under consideration when the exact engineering parameters are not yet known.
Proposed Development	Term used to define the Offshore Infrastructure associated with the Project seaward of MHWS for which consent is being sought. Further details of the parameters are included in Volume 1, Chapter 3: Project Description.
Safety Zones	An area extending a maximum of 500 m from the central point of a subsea installation in which other vessels are prohibited from entering, except in circumstances outlined within Section 96 of the Energy Act, 2004
Scoping Opinion	A document produced by MD-LOT, which is issued in response to submission and review of the Offshore Scoping Report. The Scoping Opinion is supported with feedback and advice from consultees, which details what is expected to be included in the Offshore EIA Report and what can be scoped out of the EIA process.
Scottish Ministers (the)	The decision makers with regard to Marine Licence(s) and Section 36 Consent applications in Scottish Offshore Waters and Scottish Marine Area.
Scottish Offshore Waters	The area of sea beyond 12 nm but within the Scottish Exclusive Economic Zone (EEZ) up to 200 nautical miles from the coast. .
ScotWind Leasing Round	A seabed leasing round run by CES to grant property rights for the seabed in Scottish waters for new commercial scale offshore wind project development. ScotWind Leasing must be sited within POA of the SMP.
Scour Protection	Protective materials installed to avoid sediment being eroded away from the base of the foundations and/or buried subsea cable due to the flow of water.
Section 36 Consent	Scottish Ministers' consent under Section 36 of the Electricity Act 1989 required to permit the generation and operation of an energy generation station.
Sectoral Marine Plan (SMP)	A plan developed by the Scottish Government which provide the strategically planned spatial footprint for offshore wind development in Scotland.
Significance	Effect factor that is determined by the magnitude of impact along with the sensitivity of the receptor.

Defined Term	Definition
Site Boundary	The boundary within which all elements of the Proposed Development will be located. The Site Boundary comprises the Array Area and Export Cable Corridor which ends at MHWS.
Thistle Wind Partners (TWP)	Company established for the development of the Project.
Transition Joint Bay (TJB)	Used to connect the Offshore Export Cables with the onshore export cables. These are typically concrete lined and are located above MHWS.
Wind Turbines	Structures comprising of a tubular tower, rotor blades, and a nacelle which houses the Wind Turbine generator.

Acronyms

Acronym	Definition
BOWFL	Bowdun Offshore Wind Farm Limited
CAA	Civil Aviation Authority
CBRA	Cable Burial Risk Assessment
CPS	Cable Protection Systems
CTV	Crew Transfer Vessel
DSV	Dive Support Vessel
EIA	Environmental Impact Assessment
EMP	Environmental Management Plan
HDD	Horizontal Directional Drilling
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IAC	Inter-Array Cables
LAT	Lowest Astronomical Tide
LMP	Lighting and Marking Plan
MCA	Maritime and Coastguard Agency
MDS	Maximum Design Scenario
MD-LOT	Marine Directorate – Licensing and Operations Team
MHWS	Mean High Water Springs
MLWS	Mean Low Water Springs
MOD	Ministry of Defence
MPCP	Marine Pollution Contingency Plan
NEQ	Net Explosive Quantity
NLB	Northern Lighthouse Board
OLA	Option to Lease Agreement
O&M	Operation and Maintenance
OSP	Offshore Substation Platform
OWF	Offshore Wind Farm

Acronym	Definition
PDE	Project Design Envelope
PE	Polyethylene
PLGR	Pre-Lay Grapnel Run
POA	Plan Option Area
PU	Polyurethane
ROV	Remote Operated Vehicle
SOV	Service Operation Vessel
TJB	Transition Joint Bay
TWP	Thistle Wind Partners Limited
UK	United Kingdom
USV	Uncrewed Surface Vessel
UXO	Unexploded Ordnance
WMP	Waste Management Plan

Table of Units

Units	Definition
%	Percent
kg	Kilogram
kJ	Kilojoule
km	Kilometre
km^2	Square kilometre
kV	Kilovolt
m	Metre
mm	millimetres
m^2	Square Metre
m^3	Cubic Metre
m/hour	Metres per hour
mLAT	Metres above/below Lowest Astronomical Tide
MW	MegaWatt
°	Degrees

3 Project Description

3.1 Introduction

Overview

3.1.1 This chapter of the Offshore Environmental Impact Assessment (EIA) Report provides a description of the various design elements associated with the Proposed Development including the Offshore Infrastructure and activities to be undertaken throughout the construction, Operation and Maintenance (O&M), and decommissioning phases. This chapter is informed by design work carried out to date, as well as current understanding of the environment associated with the Proposed Development from the site-specific survey work undertaken by TWP, on behalf of Bowdun Offshore Wind Farm Limited (BOWFL) (hereafter referred to as 'the Applicant').

3.1.2 The following Offshore Infrastructure components are covered by this Offshore EIA Report:

- Wind Turbines;
- Wind Turbine foundations (fixed bottom);
- Offshore Substation Platforms (OSPs);
- OSP foundations (fixed bottom);
- Offshore cables (Inter-Array Cables (IAC), Interconnector Cables, and Offshore Export Cables); and
- Scour protection, cable protection and utility crossings.

3.1.3 Planning Permission in Principle, under the Town and Country Planning (Scotland) Act 1997 (as amended), was submitted on the 27 November 2025 for the onshore elements of the Project, which includes transmission infrastructure landward of Mean Low Water Springs (MLWS).

3.1.4 Where there is an overlap in jurisdiction of consenting and regulatory regimes (i.e. within the Intertidal Area), both this Offshore EIA Report and the Onshore EIA Report (BOWFL, 2025) include the relevant technical assessments.

3.1.5 The design and engineering options available for the Proposed Development were influenced by the specific conditions and environmental factors within the Site Boundary. The Applicant has carried out several studies in the early development stage to address existing unknowns and to refine the design parameters. Further studies are expected to be completed beyond the planning phase and into procurement and contracting to acquire further site-specific information which will inform the final design of the Proposed Development. This includes determining final Wind Turbine numbers, size and layout, and fixed foundation design. The detailed design will be confirmed post-consent, subject to further site investigation and technical design studies.

Purpose of Chapter

3.1.6 The purpose of this Project Description chapter is:

- to set out the individual components of the Proposed Development, as well as the main activities associated with the construction, O&M and decommissioning phases;
- to provide the maximum Project Design Envelope (PDE) for the Proposed Development, comprising information on the site, design, size and other relevant features of the Proposed Development, based on conceptual design principles and current understanding of the environment; and
- to provide the basis for the assessment of likely significant effects included in Volume 2, Chapters 7 to 23.

Project Design Envelope

3.1.7 The PDE approach (also known as the 'Rochdale Envelope') (Scottish Government, 2022) has been adopted by the Applicant for the Proposed Development. This approach presents the maximum design parameters to assess likely significant environmental effects while allowing necessary flexibility where certain development details, such as Wind Turbine and foundation types, are yet to be finalised at the time of application. Within this Offshore EIA Report, the Applicant has determined the impacts that could occur from the Proposed Development for given receptor groups and has identified, from the ranges within the PDE, those parameters that present the greatest impact(s) on the specific receptor group (the 'Maximum Design Scenario (MDS)'. As a result, for each topic-specific assessment, the Proposed Development's actual effects resulting from any design selected from the PDE will be equal to or less than those effects assessed. The PDE approach is referenced in guidance prepared by the Marine Directorate and the Energy Consents Unit (June 2022) for applications under Section 36 of the Electricity Act 1989[1].

3.1.8 However, it is important that a sufficient level of detail is included, such as consideration of a range of possibilities, to allow assessment of the likely significant environmental effects (as defined by the EIA Regulations) and any necessary mitigation measures (Scottish Government, 2022). For example, where the foundation types of a development are not yet confirmed, the PDE approach would consider the foundations with the largest footprint for habitat loss, as this is likely to have the greatest potential for impact on the seabed. If an impact assessment is undertaken on this basis and no likely significant environmental effects are identified, it can be assumed that any variations to project parameters equal to or less than the assessed parameter (i.e. within the assessed 'envelope') will not result in a likely significant environmental effect for the topic and impact under consideration.

[1] https://www.gov.scot/publications/guidance-applicants-using-design-envelope-applications-under-section-36-electricity-act-1989/

3.1.9 Within this Offshore EIA Report, the Applicant has determined the impacts for given receptor groups and defined, from the PDE ranges, the MDS for each receptor. Consequently, for each topic-specific assessment, predicted effects for any alternative parameter within the range will be no greater than those assessed for the MDS. The PDE describes a range of parameters that apply to a specific technology design scenario. For example, Wind Turbine size and Wind Turbine number are inherently correlated so if larger Wind Turbines are selected, fewer Wind Turbines are likely to be required to achieve the same generating capacity. Therefore, each design parameter set out in this chapter is not considered independently.

3.1.10 The largest parameters set out in this chapter will not necessarily comprise the MDS for any given receptor group and each of the impacts assessed within the technical assessments (Volume 2, Chapters 7 to 23).

3.1.11 Since the submission of the Bowdun Offshore Wind Farm (OWF) Offshore Scoping Report (BOWFL, 2024), the Applicant has developed and refined the PDE for the Offshore EIA Report using the results of early engineering studies and information gained through stakeholder consultation. A description of the PDE refinements for the Proposed Development is provided within Volume 1, Chapter 6: Site Selection and Consideration of Reasonable Alternatives, however, in summary, the following parameters have changed:

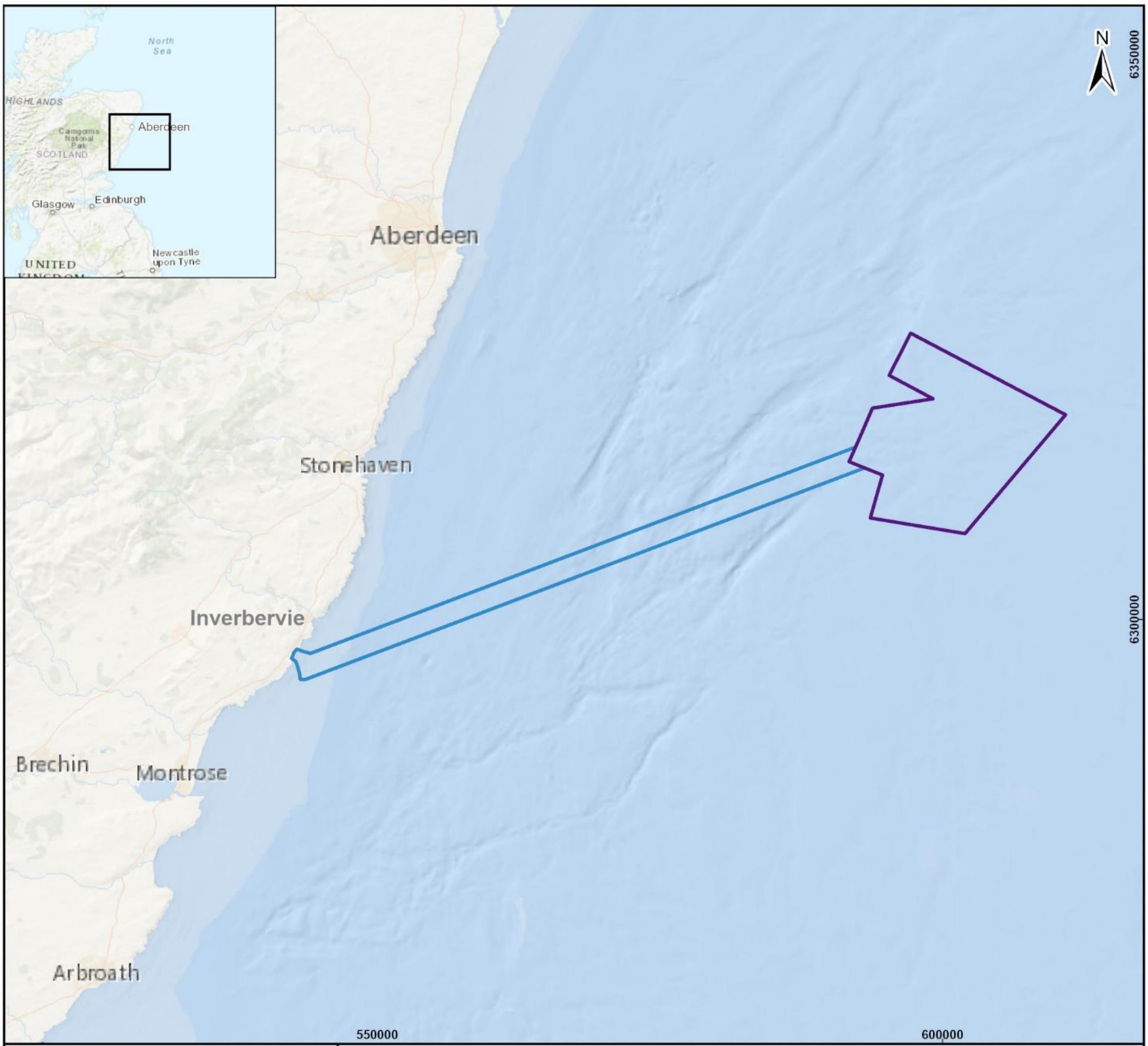
- refinement in Wind Turbine foundations to fixed, with floating foundations no longer considered;
- reduction in fixed Wind Turbine foundation options to monopiles, piled jackets (3 or 4-legged), or suction bucket jackets (3-legged);
- refinement of piling parameters for Wind Turbine foundations and OSPs;
- increasing the Air Gap from 25.36 m to 33.12 m above Lowest Astronomical Tide (LAT); and
- refinement of Offshore Export Cable installation at Landfall to trenchless technology only (e.g. Horizontal Directional Drilling (HDD)).

3.1.12 Once additional information becomes available from further site investigations, the final detailed design will be developed further, with commercial availability of technologies influencing future design. It should be noted, the final design will remain within the presented PDE parameters. This flexible, iterative approach is standard for large-scale energy projects such as this Proposed Development and allows the design to address environmental considerations where practicable.

Location and Site Information

3.1.13 The Site Boundary comprises of the Array Area, which is located in the E3 Plan Option Area (POA) detailed in the Scottish Sectoral Marine Plan (Scottish Government, 2020), and the Export Cable Corridor. The Array Area is located 38 km from the Aberdeenshire coast at its closest point from land and covers an area of 187 km^2 (Figure 3.1). The Export Cable Corridor extends from the Array Area and will make landfall at Benholm, Aberdeenshire.

3.1.14 The Applicant was awarded an Option to Lease Agreement (OLA) to develop the Bowdun OWF Project within the E3 POA in January 2022 as part of the ScotWind Leasing Round (please see Volume 1, Chapter 6: Site Selection and Consideration of Reasonable Alternatives).



Project Title: Bowdun Offshore Wind Farm

Figure Title: Proposed Development Site Boundary

LEGEND

- Array Area
- Export Cable Corridor

0 2.5 5 10 nm

0 5 10 20 km

Geodetic Information:
Datum: ETRS 1989
Projection: ETRS 1989 UTM Zone 30N

Data Sources: Client,

Service Layer Credits: World Topographic Map: Esri, HERE, Garmin, FAO, NOAA, USGS
World Ocean Base: OceanWise, Esri, GEBCO, Garmin, NaturalVue
World Light Gray Reference: Esri, HERE

VER	DATE	DETAILS	BY	CHK
00	29/04/25	First Issue	MJ	JC
01	30/09/25	Revision	MJ	CR
02	10/10/25	Revision	MJ	CR
-	-	-	-	-

Drawing Number: EOR0770A-ES-MISC-001-02

THISTLE WIND PARTNERS
TETRA TECH RPS ENERGY

Figure 3.1: Proposed Development Site Boundary

Water depths and Seabed within the Proposed Development

3.1.15 A geophysical survey covering the Array Area and part of the Export Cable Corridor was carried out in 2023 and 2024 to collect both geophysical and bathymetric data. For the geophysical coverage see Figure 3.1 in Volume 3, Technical Appendix 7.1: Physical Processes Baseline Environment.

3.1.16 The bathymetry within the Export Cable Corridor ranges from 0 m in the nearshore area to a maximum depth of -113 m from LAT within the Export Cable Corridor. In the nearshore areas, bedrock outcrops create a complex terrain with significant slope variations, reaching up to 83° in some areas. Further offshore, average slopes are generally below 5°. Within the Array Area, water depths are typically in the range -54 m LAT to -91 m LAT. Overall, the Array Area is characterised by generally flat terrain, although local gradients become steeper in areas where bedforms are present.

3.1.17 Further details of the bathymetry and seabed composition are presented within Volume 2, Chapter 7: Physical Processes and Volume 2, Chapter 8: Benthic Ecology.

3.2 Proposed Infrastructure

Overview

3.2.1 The main components of the Proposed Development, as shown in Figure 3.2, will include:

Offshore Generation Assets

- up to 67 Wind Turbines (each comprised of three rotor blades, a nacelle housing the generating unit, hub and tower section) and associated supporting structures which will be fixed foundations;
- a network of up to 167 km of IACs which will be static cables;
- up to 36 km of Interconnector Cables; and
- scour protection, cable protection and utility crossings.

Offshore Transmission Assets

- up to three OSPs with fixed foundations and supporting infrastructure including scour protection (as required);
- up to three Offshore Export Cables totalling approximately 210 km in length; and
- cable protection and utility crossings where required.

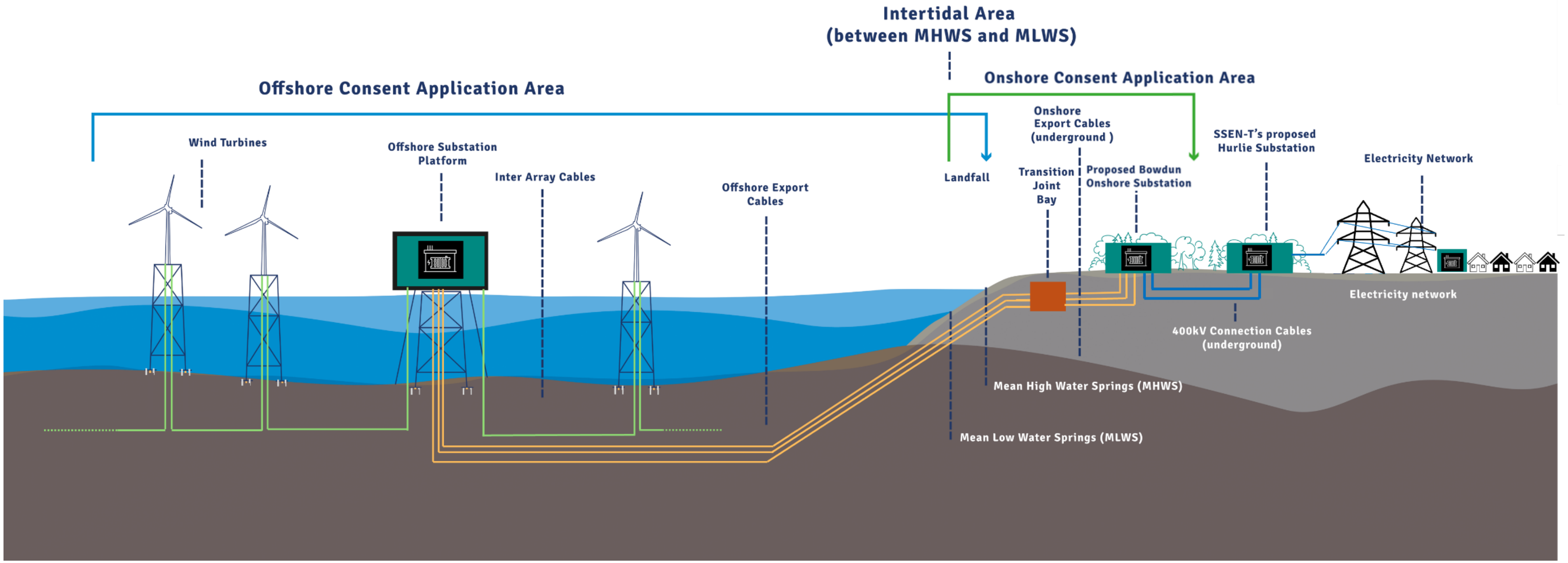


Figure 3.2: Project Overview

3.2.2 The following sections of this chapter provide further detail for each design aspect, along with the maximum and minimum scenarios that comprise the PDE. However, the high-level parameters of the Proposed Development are summarised in Table 3.1.

Table 3.1: High Level Design Parameters of the Proposed Development

Parameter	Design
Estimated construction period	Up to 5 years
Array Area (km^2)	187
Distance of Array Area from the shore at closest point (km)	38
Maximum number of Wind Turbines	67
Wind Turbine maximum rotor diameter (m)	326
Wind Turbine maximum tip height from LAT (m)	359.12
Maximum number of OSPs	3
Maximum number of Offshore Export Cables	3
Export transmission system	High Voltage Alternating Current (HVAC)
Maximum length of IAC (km)	167
Maximum length of Interconnector Cable (km)	36
Maximum length of Offshroe Export Cable (km)	210

3.2.3 Annex A presents the coordinates of the Proposed Development within which the Offshore Infrastructure will be located.

3.3 Offshore Generation Assets

Wind Turbines

3.3.1 The Proposed Development will comprise up to 67 Wind Turbines, however, the final number of Wind Turbines will be determined by the capacity of the individual Wind Turbines selected, as well as the results of the environmental and engineering surveys.

3.3.2 This PDE will consider a range of Wind Turbine parameters which account for varying generating capacities and will allow a degree of flexibility to account for anticipated technological developments in the future whilst allowing the MDS to be defined for each potential impact within the technical assessments (Volume 2, Chapters 7 to 23). Therefore, the Wind Turbine parameters presented in this section, and for which consent is sought, represent the maximum Wind Turbine parameters as presented in the PDE, such as maximum rotor blade diameter and maximum blade tip height.

3.3.3 Table 3.2 presents the range of parameters considered for the Wind Turbines and considers both the maximum number of Wind Turbines and the largest Wind Turbines described within the PDE. Therefore, the parameters in combination do not represent a realistic design scenario, but the most likely range of Wind Turbine parameters that could be available post-consent/at the time of construction of the Proposed Development.

3.3.4 The Wind Turbines will consist of a tower section, nacelle, hub and three rotor blades, attached to a fixed foundation (these foundations are further discussed in Paragraphs 3.3.13 to 3.3.23).

3.3.5 The maximum rotor blade diameter will be no greater than 326 m, with a maximum blade tip height of up to 359.12 m above LAT and a minimum Air Gap of 33.12 m above LAT. The hub height will be no greater than 196 m above LAT. As part of the Lighting and Marking Plan (LMP) (Volume 4, Appendix 31: Outline Lighting and Marking Plan) the Applicant will develop and agree a scheme for Wind Turbine lighting and navigation marking with the relevant consultees post-consent decision for approval by Scottish Ministers after consultation with appropriate consultees.

3.3.6 The Wind Turbine layout will be developed to effectively make use of the available wind resource, suitability of seabed conditions, whilst also ensuring that the environmental effects and potential impacts on other marine users (e.g. fisheries, shipping routes, and subsea cables) are mitigated. The Wind Turbine layout will take account of the agreed buffers with Scottish and Southern Electricity Network (SSEN) and National Grid for the Eastern Green Link (EGL) 2 High Voltage Direct Current (HVDC) cable (see Volume 2, Chapter 16: Infrastructure and Other Users).

3.3.7 Figure 3.3 presents an indicative Proposed Development layouts for the 67 (15 MW) Wind Turbine locations, plus seven spare locations, plus three OSP locations. The spare Wind Turbine locations provide alternative locations should seabed conditions be challenging for installation. The final layout will only be up to a maximum of 67 Wind Turbines and up to three OSPs, and will be confirmed prior to construction.

3.3.8 Figure 3.4 presents an indicative Proposed Development layouts for the 40 Wind Turbine locations, plus four spare locations, plus three OSP locations.

3.3.9 The OSP locations shown in Figure 3.3 and Figure 3.4 are shown for illustrative purposes, and the final locations will be determined at the final design stage (post-consent). Further information on OSPs is provided in Paragraphs 3.4.1 to 3.4.7.

Table 3.2: PDE for the Wind Turbines

Parameter	Maximum Design		
	Option 1	Option 2	Option 3
Maximum number of Wind Turbines	67	50	40
Minimum Air Gap above LAT (m)	33.12		
Maximum blade tip height above LAT (m)	269.12	309.12	359.12
Maximum hub height above LAT (m)	151	171	196
Maximum rotor diameter (m)	236	276	326
Maximum number of blades	3		

Parameter	Maximum Design		
	Option 1	Option 2	Option 3
Minimum Wind Turbine spacing (m), measured perpendicular to the prevailing wind direction	1,038	1,259	1,467

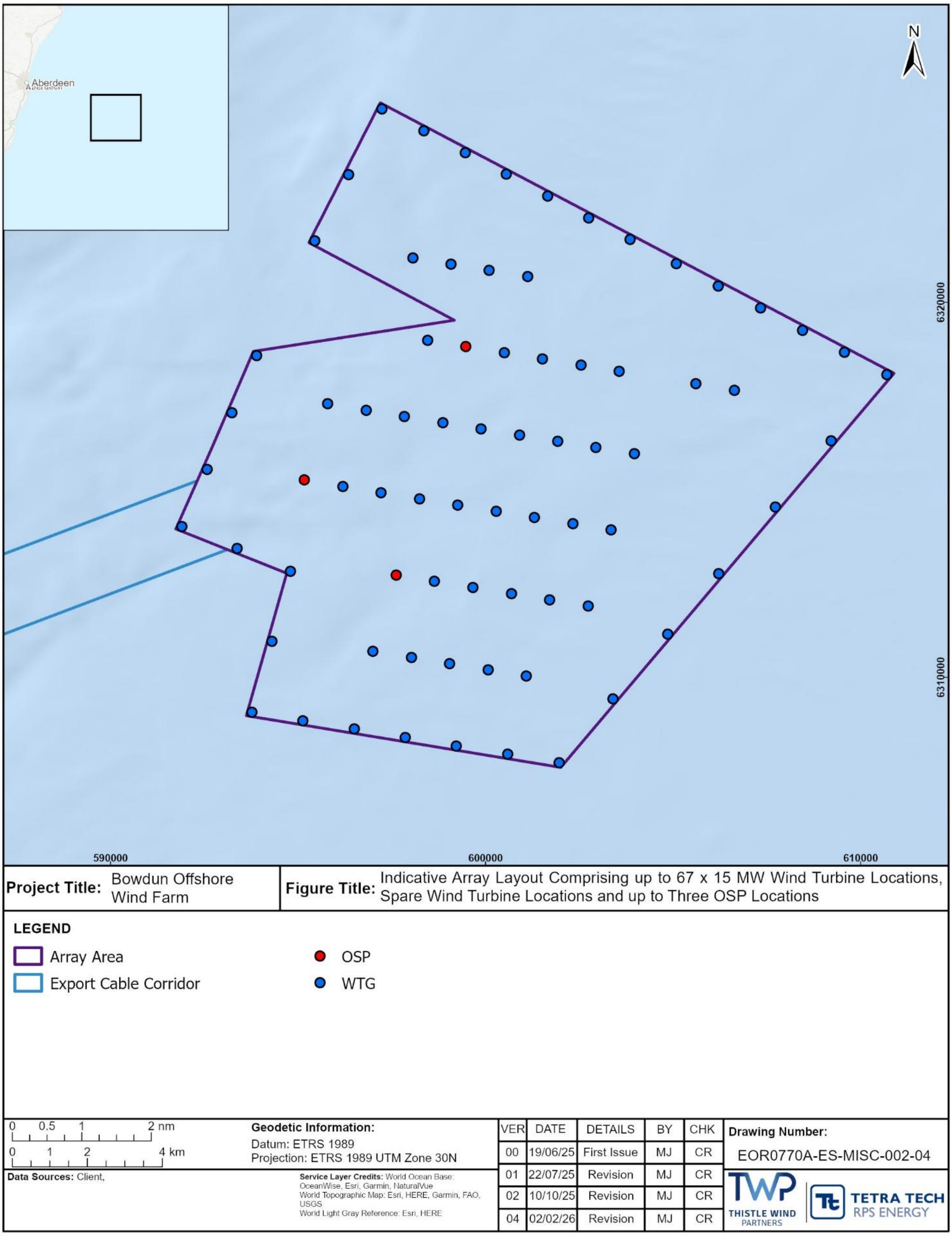
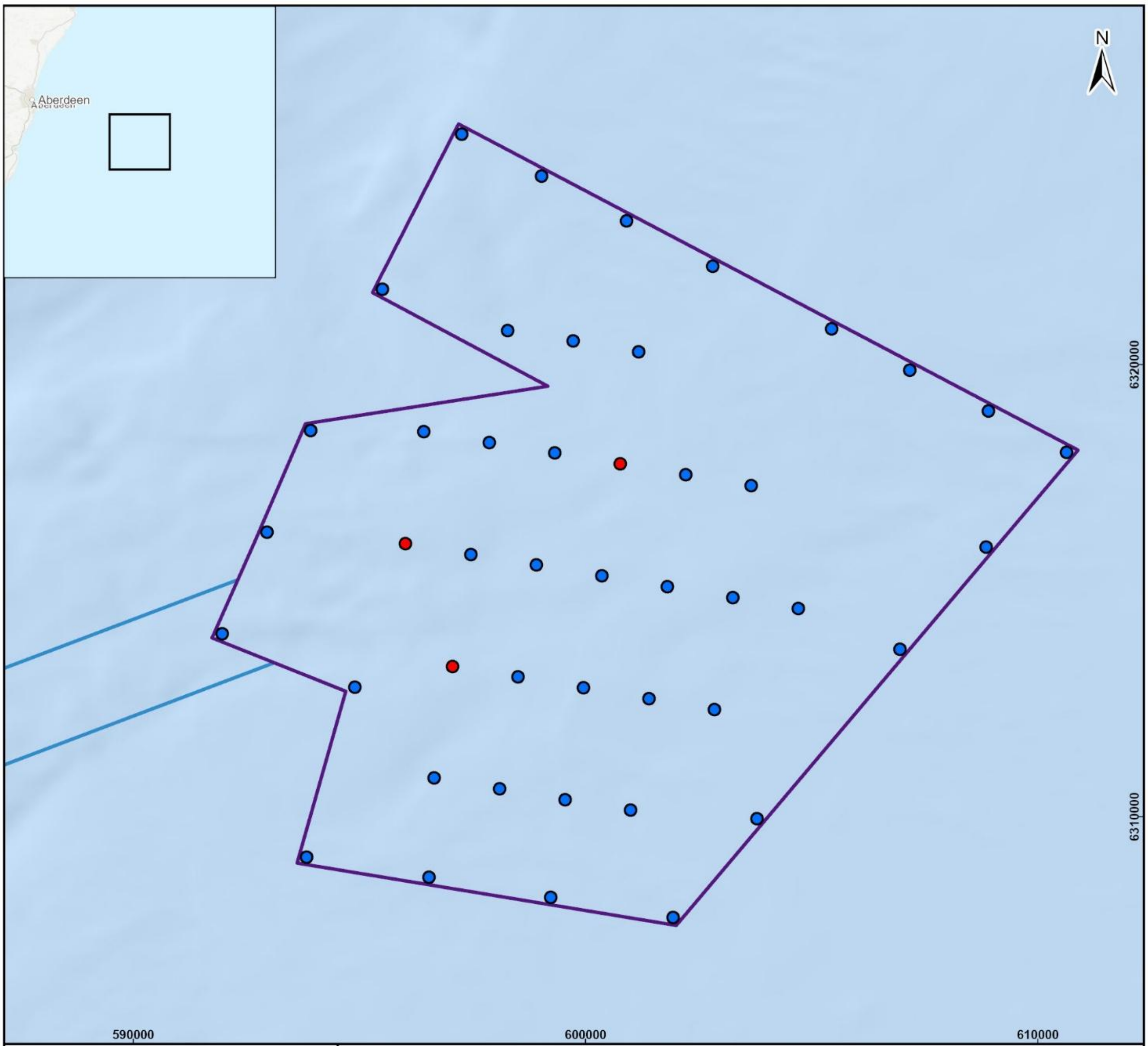


Figure 3.3: Indicative Array Layout Comprising up to 67 x 15 MW Wind Turbine Locations, Spare Wind Turbine Locations and up to 3 OSP Locations



Project Title: Bowdun Offshore Wind Farm

Figure Title: Indicative Array Layout Comprising up to 40 x 25 MW Wind Turbine Locations, Spare Wind Turbine Locations and up to Three OSP Locations

LEGEND

- Array Area
- Export Cable Corridor
- OSP
- WTG

0 0.5 1 2 nm
0 1 2 4 km

Geodetic Information:
Datum: ETRS 1989
Projection: ETRS 1989 UTM Zone 30N

VER	DATE	DETAILS	BY	CHK
00	19/06/25	First Issue	MJ	CR
01	10/10/25	Revision	MJ	CR
02	09/12/25	Revision	MJ	CR
03	02/02/26	Revision	MJ	CR

Drawing Number: EOR0770A-ES-MISC-004-03

Data Sources: Client,

Service Layer Credits: World Ocean Base: OceanWise, Esri, Garmin, NaturalVue
World Topographic Map: Esri, HERE, Garmin, FAO, NOAA, USGS
World Light Gray Reference: Esri, HERE

THISTLE WIND PARTNERS
TETRA TECH RPS ENERGY

Figure 3.4: Indicative Array Layout Comprising up to 40 x 25 MW Wind Turbine Locations, 4 Spare Wind Turbine Locations and up to 3 OSP Locations

3.3.10 A number of consumables will be required throughout the Proposed Developments lifecycle to improve operation, productivity and reduce wear on parts of Wind Turbines. These may include:

- grease;
- synthetic oil;
- hydraulic oil;
- gear oil;
- lubricants;
- nitrogen;
- water/glycerol;
- transformer silicon/ester oil;
- diesel fuel;
- Sulphur Hexafluoride; and
- glycol/coolants.

3.3.11 Required quantities of each consumable will be dependent upon the final design of the Wind Turbines selected. Any potential release of chemicals into the marine environment via an accidental pollution event during the construction, O&M and decommissioning phases will be reduced as far as reasonably practicable through implementation of appropriate controls and mitigation as set out in an Environmental Management Plan (EMP), including a Marine Pollution Contingency Plan (MPCP), and the Decommissioning Programme. An outline EMP, including an MPCP, is presented in Volume 4, Appendix 24: Outline Environmental Management Plan.

Wind Turbine Foundations and Support Structures

3.3.12 The Proposed Development will consist of Wind Turbines supported by fixed foundations. The following subsections describe the PDE for the fixed foundations.

Fixed Foundations

3.3.13 To allow for flexibility in foundation choice, monopile, piled jacket (three or four legs), or suction bucket jacket (three legs) foundations are being considered for the Proposed Development. The Proposed Development's final design will be dependent on the type of Wind Turbine used as well as the results of environmental and site investigation surveys.

3.3.14 It is anticipated that foundations will be fabricated onshore before specialist vessels are used to transport and install the foundations within the Array Area. Scour protection (typically rock) may be required on the seabed and will be installed before and/or after foundation installation (see Paragraph 3.3.27 to 3.3.29).

3.3.15 The following sections provide an overview of the design parameters associated with each fixed foundation type being considered for the Wind Turbines within the PDE for the Proposed Development.

Monopile

3.3.16 Monopile foundations are comprised of a solitary steel tubular, which is piled into the seabed at a singular point. These foundation types are often accompanied by a transition piece, which covers part of the pile and acts to level the Wind Turbine and allows for the installation of additional substructures, such as ladders or boat landings (Figure 3.5).

3.3.17 The installation of monopile foundations will be undertaken using one of two primary methods, either piling, or drive-drill-drive. The choice of method will depend on factors such as seabed conditions and the dimensions of the monopiles. Piling typically involves the use of hydraulic hammers or vibration techniques, while the drive-drill-drive method incorporates piling, followed by drilling to penetrate hard seabed layers and potentially further piling to achieve the required depth. Paragraphs 3.6.11 to 3.6.15 provide further information on the piling installation methodology. These activities are generally conducted from jack-up or floating vessels. Any drilling spoil will typically be deposited adjacent to the drill site. Paragraphs 3.6.17 to 3.6.18 provide further information on the drilling installation methodology. Installation equipment may operate above or below the sea surface. A combination of these methodologies may be employed across the Array Area.

3.3.18 The PDE for the Proposed Development includes a maximum of 67 monopiles. At present, it is anticipated that up to two vessels may be utilised to install up to two monopiles concurrently with a maximum hammer energy of 6,250 kJ.

3.3.19 To mitigate potential acoustic impacts from pilling, which will be determined by the subsea noise impact assessment, a 'soft start' procedure would be implemented. This procedure involves beginning the process of piling with reduced hammer energy before slowly ramping up to the maximum hammer energy within an agreed timescale.

3.3.20 Table 3.3 outlines the maximum PDE for the key design parameters of monopile foundations within the Proposed Development, and an illustrative monopile foundation is shown in Figure 3.5.

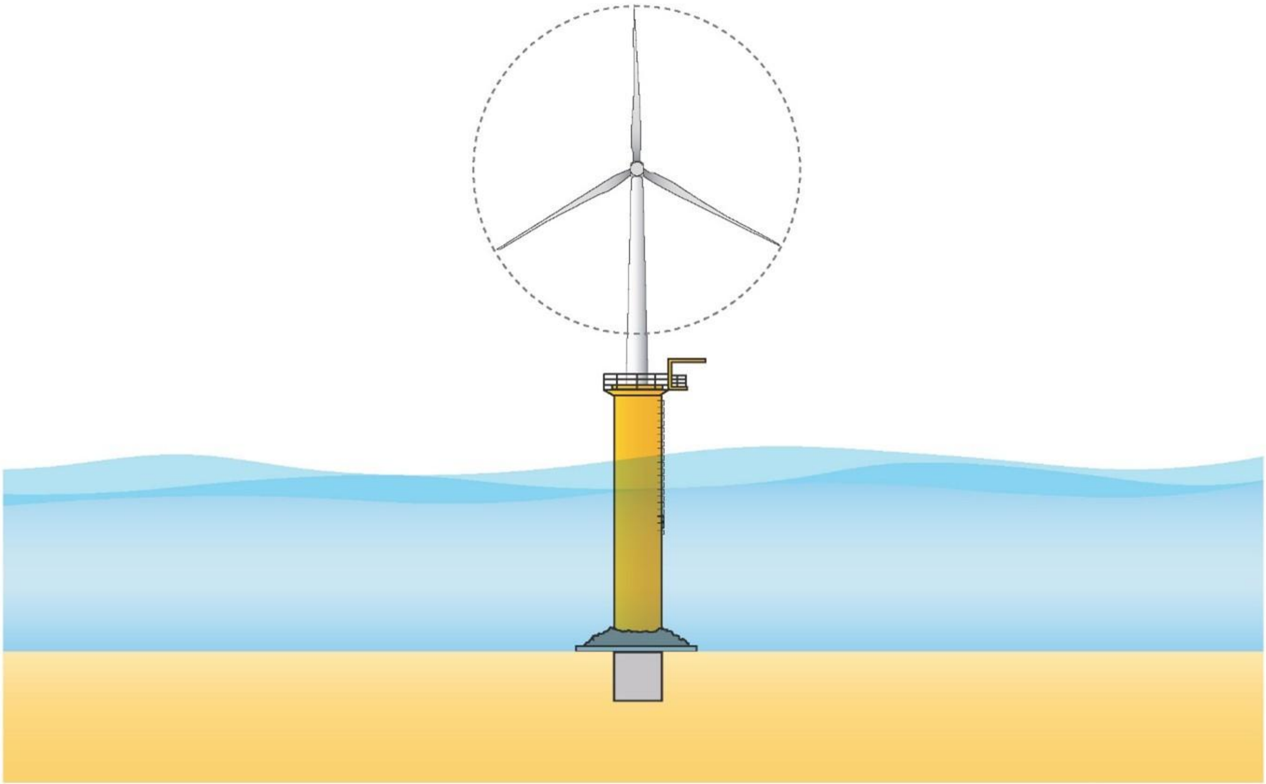


Figure 3.5: Monopile Foundation Design

Table 3.3: PDE for Monopile Foundations

Parameter	Maximum Design	
	15 MW Wind Turbines	25 MW Wind Turbines
Maximum number of monopile foundations	67	40
Monopile diameter at seabed (m)	13	15
Maximum monopile/transition piece diameter at interface (m)	8	9
Total monopile length	123	
Transition piece length (m)	26	
Total length (tower interface to bottom of monopile)	149	
Maximum pile penetration depth (m)	45	
Maximum seabed footprint per foundation (m^2)	132.7	176.7
Maximum seabed footprint for the Array Area (m^2)	8,893	7,069
Maximum scour protection footprint (per foundation) (m^2)	3,318	4,418

Parameter	Maximum Design	
	15 MW Wind Turbines	25 MW Wind Turbines
Maximum area foundation footprint (per foundation) (m^2) including scour protection[2]	3,318	4,418
Maximum seabed footprint for the Array Area (m^2) (foundation and scour protection)	222,327	176,715
Maximum hammer energy (kJ) (maximum energy theoretically possible)	6,250	6,250

Piled or Drilled Jacket Foundations

3.3.21 Jacket foundations consist of steel tubular members welded together to form a lattice like structure with three or four legs. The structure is typically fixed to the seabed with driven and/or drilled pin piles (see Figure 3.6). The diameters of the pin piles associated with piled jacket foundations are lower than monopile foundations, however similar technology is utilised for their installation: hydraulic hammers, vibration, and drilling into the seabed. A combination of piling and drilling, including drive-drill-drive scenarios may be required.

3.3.22 The PDE for the Proposed Development is based on a maximum of 67 jacket foundations being required, with options for three or four legs per foundation and one pile per leg. It is expected that up to two vessels will be utilised to install pin piles concurrently, using a maximum hammer energy of 4,500 kJ. During jacket installation, grout will be used to fill the gap between the jacket legs and the piles to ensure structural integrity. This grouting process may require the use of a separate vessel dedicated to grout operations.

3.3.23 The PDE for parameters of piled jacket foundations installations for Wind Turbines within the Proposed Development is detailed in Table 3.4, which includes both three and four leg foundation options.

[2] Scour protection is usually pre-installed. The foundation is then installed through the scour protection, so the total footprint remains the same as with scour protection only.

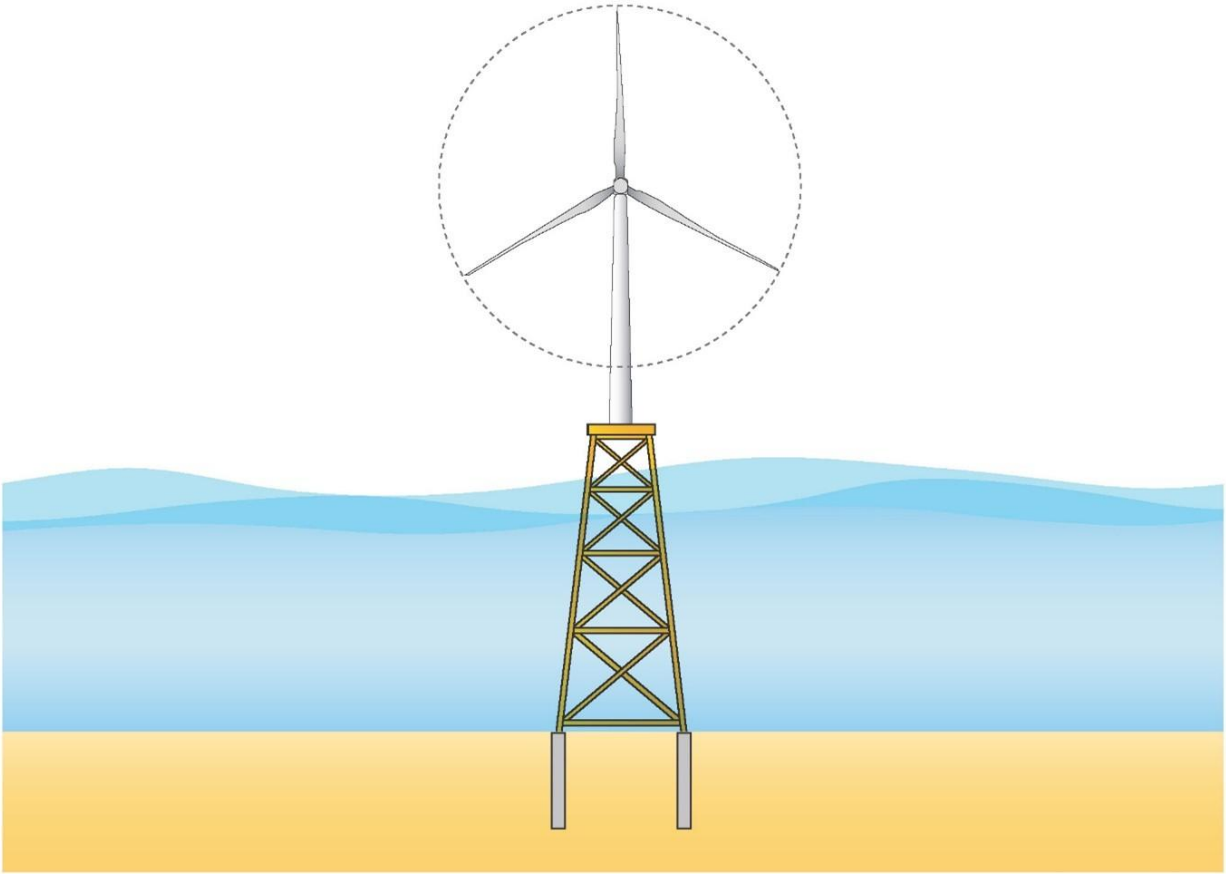


Figure 3.6: Piled Jacket Foundation Design

Table 3.4: PDE for Piled Jacket Foundations

Parameter	Maximum Design (3-legged)		Maximum Design (4-legged)	
	15 MW Wind Turbines	25 MW Wind Turbines	15 MW Wind Turbines	25 MW Wind Turbines
Maximum number of jacket foundations	67	40	67	40
Maximum number of piles per leg	1	1	1	1
Maximum number of piles	201	120	268	160
Maximum diameter of jacket leg (m)	3.3	4.5	3.1	4.3
Maximum diameter of piles (m)	4.1	5.0	3.8	5.0
Concurrent piling events	2	2	2	2
Maximum expected pile penetration depth (m)	70	85	65	80
Maximum seabed footprint per jacket (m^2)	39.6	58.9	45.4	78.5
Maximum seabed footprint for all jacket foundations (m^2)	2,654	2,356	3,039	3,142
Maximum scour protection footprint (per jacket) (m^2)	2,206	3,054	2,606	4,072

Parameter	Maximum Design (3-legged)		Maximum Design (4-legged)	
	15 MW Wind Turbines	25 MW Wind Turbines	15 MW Wind Turbines	25 MW Wind Turbines
Maximum area foundation footprint (per jacket) (m^2) including scour protection[3]	2,206	3,054	2,606	4,072
Maximum seabed footprint for the Array Area (m^2)	147,819	122,145	174,586	162,860
Maximum hammer energy (kJ) (maximum energy theoretically possible)	4,500	4,500	4,500	4,500
Realistic maximum average hammer energy (kJ)	4,275	4,275	4,275	4,275

Jacket Foundations with Suction Buckets

3.3.24 Jacket foundations with suction buckets consist of steel tubular members welded together to form a lattice like structure with three legs. The end of each leg is attached to a suction bucket (typically a hollow, steel cylinder, capped on the upper end), which affixes the structure to the seabed (illustrated in Figure 3.7)

3.3.25 Suction bucket foundations do not require noisy installation measures, such as piling. Rather, after the foundations have been transported to the Array Area and lowered to the seabed, water is pumped from each of the buckets, which creates a suction that pulls the foundation legs into the seabed. When the desired burial depth is reached, the void is filled with a thin layer of grout, which is injected under the top side of the bucket. This also ensures contact between the seabed substrate within the bucket and the top of the bucket itself.

3.3.26 The PDE is based on a maximum of 67 suction jacket foundations being required with three legs per foundation. The key parameters included in the PDE for the installation of suction bucket jacket foundations within the Proposed Development are detailed in Table 3.5.

[3] Scour protection is usually pre-installed. The pile is then installed through the scour protection, so the total footprint remains the same as with scour protection only.

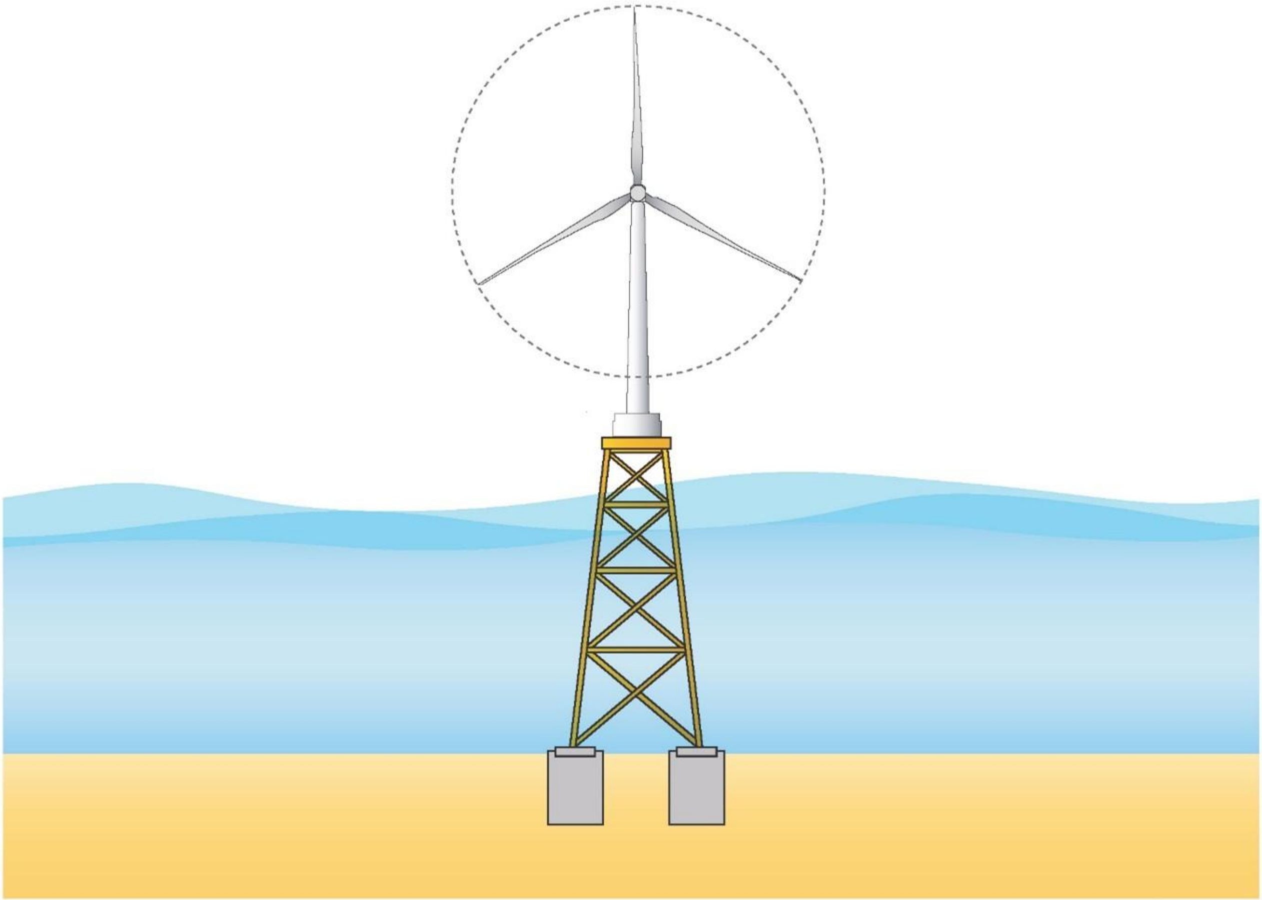


Figure 3.7: Jacket Foundations with Suction Buckets Design

Table 3.5: PDE for Jacket Foundations with Suction Buckets

Parameter	Maximum Design (3-legged)	
	15 MW Wind Turbines	25 MW Wind Turbines
Maximum number of jacket foundations	67	40
Maximum number of suction cans per leg	1	1
Total suction bucket height (m)	19	23
Maximum diameter of jacket leg (m)	3.3	4.5
Maximum diameter of suction buckets (m)	17.0	19.0
Suction bucket penetration depth (m)	15	19
Suction bucket stick up (void height) (m)	1.5	1.5
Grout volume per suction bucket (m^3)	340.5	425.3
Grout volume for Array Area (m^3)	68,434	51,035
Maximum seabed footprint per jacket (m^2)	680.9	850.6
Maximum seabed footprint for all jacket foundations (m^2)	45,623	34,023
Maximum scour protection footprint (per jacket) (m^2)	3,300	3,600

Parameter	Maximum Design (3-legged)	
	15 MW Wind Turbines	25 MW Wind Turbines
Maximum seabed footprint for the Array Area (m^2)	221,100	144,000

Scour Protection for Foundations

3.3.27 The hydrodynamic processes and associated sedimentary movements within the Site Boundary may result in seabed erosion and the formation of 'scour holes' around the Wind Turbine foundations. A number of factors influence the development of scour, including the shape of structures on the seabed, seabed sedimentology, and site-specific metocean conditions (e.g. storms, waves, and currents). Commonly used scour protection types include:

- rock: the most frequently used scour protection method. Layers of graded stones placed on and/or around structures (e.g. foundation structures) to inhibit erosion, or rock filled mesh fibre bags which adapt to the shape of the seabed/structure as they are lowered on to it; or
- concrete mattresses: cast of articulated concrete blocks, several metres wide and long and linked by a polypropylene rope lattice, which are placed on and/or around structures to stabilise the seabed and inhibit erosion.

3.3.28 The type and volume of scour protection required will vary depending on the various Wind Turbine foundation options. The final parameters will be decided once the design of these is finalised. This decision will consider a range of aspects including geotechnical data, meteorological and oceanographical data, water depth, foundation type, maintenance strategy and cost.

3.3.29 Table 3.6 presents the PDE for scour protection required for the Wind Turbine foundation options described in Paragraphs 3.3.16 to 3.3.26.

Table 3.6: PDE for Scour Protection for Foundation Options

Parameter	Maximum Design		
	Monopile with transition piece	4-legged piled or drilled wind turbine jacket foundations	3-legged wind turbine jacket foundations with suction buckets
Maximum number of Wind Turbines	67	67	67
Scour protection type	Rock and concrete mattresses	Rock and concrete mattresses	Rock and concrete mattresses
Maximum height of scour protection (m)	1	1	1
Maximum diameter of scour protection (per pile for jacket foundations) (m)	65.0	28.8	38.0
Maximum area of scour protection per foundation (excluding pile area) (m^2)	3,318	2,606	3,300

Parameter	Maximum Design		
	Monopile with transition piece	4-legged piled or drilled wind turbine jacket foundations	3-legged wind turbine jacket foundations with suction buckets
Maximum volume of scour protection per foundation (m^3)	3,318	2,606	3,300
Maximum volume of scour protection for Proposed Development (m^3)	222,327	174,586	221,100

Inter-Array Cables

3.3.30 The electrical current produced by the Wind Turbines will be carried to the OSPs via IACs. Typically, several Wind Turbines will be grouped together on the same cable 'string', which connects the Wind Turbines to an OSP. Multiple cable 'strings' will then connect back to each OSP.

3.3.31 There may also be an IAC backlink introduced to connect Wind Turbines at the end of two strings, which will allow for partial re-routing of power in case of cable failure. The backlink may also be used to supply power (backup supply) to the ancillaries of the Wind Turbines in the affected string. The exact location and lengths of the IACs, along with the possible backlinks, will be dependent on the final design of the Proposed Development and will be considered in parallel to the final Wind Turbine layout.

3.3.32 The Proposed Development PDE currently considers the use of static IACs. The static IACs will enter and exit potential jacket foundations (both Wind Turbine and OSPs) through J-tubes, and enter and exit potential monopile foundations through I-tubes or cable entry holes. Between the Wind Turbines and OSPs, static IACs are laid directly on the seafloor and/or buried.

3.3.33 Where the IACs are laid on the seabed, they will be buried to an appropriate target burial depth. Cable burial depths will be informed by a Cable Burial Risk Assessment (CBRA) but based on current information it is anticipated that target burial depths will be 1.5 m (subject to further design), with greater burial depths targeted in specific areas as informed by the CBRA. In cases where such burial is not feasible (e.g. the foundation entry points, or where the cable is expected to cross areas of bedrock/hard ground, pipelines, or other existing cables), alternative protection methods will be employed, such as Polyurethane (PU), Polyethylene (PE), steel, or iron Cable Protection Systems (CPS) at the exit/entry of J-tubes, rock protection, grout bags, concrete mattresses, and/or protective sleeves. Additionally, scour protection may be installed over cables and CPS at the base of turbine foundations. See Paragraph 3.3.43 for further information on external cable protection. The CBRA will be prepared as a post-consent (and finalised prior to construction) and its findings will inform the target burial depths, any required alternative protection measures and the Cable Plan, this commitment is recorded in Volume 3, Technical Appendix 4.6: Schedule of Mitigation and Commitments.

3.3.34 The need for additional external protection will be subject to whether minimum target cable burial depths recommended for protection from the external threats can be achieved. Additional external protection will also be required at cable crossings, where cables cross existing assets. Seabed conditions, sedimentology, naturally occurring physical processes and potential interactions with human activities, such as vessel anchoring and bottom-trawl fishing gear, are all factors that can influence the requirement for the need of additional protection.

3.3.35 Although a minimum target burial depth is identified, where burial to that target is not achievable cables may be protected above the seabed using the full range of feasible protection measures; the PDE therefore includes both the target burial depths and the full range of above-seabed protection options so that each topic-specific assessment has considered the worst-case combination of burial depth and above-seabed protection.

3.3.36 Installation of the IACs may be undertaken using pre-lay plough, plough, trenching, cutting, and/or jetting techniques. Fundamentally, these techniques all involve the displacement of sediments (either by mechanical tools or water jets) on or above the seabed. This creates a trench into which the cable(s) may be lowered. The target burial depth for the IACs is typically 1.5 m below the undisturbed seabed level, with a minimum target burial depth of 0.5 m where achievable and subject to the outcomes of the CBRA and O&M requirements. In areas of high seabed mobility, deeper burial depths may be required to ensure long-term cable stability.

3.3.37 In specific locations identified through the CBRA, such as crossings of existing pipelines, cables, or other subsea infrastructure, or where hard seabed conditions are encountered, cables may be installed directly on the seabed without burial. In such cases, external protection measures such as rock bags or concrete mattresses would be employed to safeguard the cables. Additionally, in high-risk areas such as shipping lanes, burial depths may be greater to mitigate the risk of anchor strikes or to accommodate potential future seabed deepening.

3.3.38 Section 3.5 covers site preparation activities that may be required in order to provide a relatively flat seabed surface for the installation of cables and allow the burial of IACs to the target burial depths.

3.3.39 The cable burial methodology and potential external cable protection will be identified at the final design stage (post-consent). The PDE for IACs is presented in Table 3.7.

Table 3.7: PDE for Inter-Array Cables

Parameter	Maximum Design
Maximum voltage (kV)	132
Maximum total cable length (km)	167
Maximum external cable diameter (mm)	315
Minimum external cable diameter (mm)	250
Maximum length of cable on the seabed (km)	151
Maximum length of cable in the water column (km)	N/A
Cable burial methodology	Lay then burial and/or simultaneous lay and burial. Ploughing/jetting/cutting Multiple installation techniques to be achieved using hybrid installation equipment.
Target burial depth (m)	1.5
Minimum target burial depth (m)	0.5 (subject to CBRA)
Maximum width of cable trench (m)	6
Maximum width of seabed affected from installation tool per cable (m)	25
Maximum total area of seabed disturbance (km^2)	3.78
Maximum annual length of re-burial (m)	4,915

Interconnector Cables

3.3.40 Interconnector cables will be required to connect the OSPs to each other in order to provide redundancy in the case of failures within the electrical transmission system. Each OSP will be connected to the other OSP(s) within the Array Area using Interconnector Cables.

3.3.41 Where practicable the cables will be buried to an appropriate target burial depth. Cable burial depths will be informed by a CBRA but based upon current knowledge, target burial depths will be 1.5 m, with greater burial depths targeted in specific areas (e.g. in areas of increased shipping density). In cases where such burial is not feasible (e.g. the foundation entry points, or where the cable is expected to cross areas of bedrock, pipelines, or other existing cables), alternative protection methods will be employed, such as PU, PE, steel, or iron CPS, rock placement, rock/grout bags, concrete mattresses, and/or protective sleeves.

3.3.42 Interconnector Cables will be installed by the same methodologies proposed for IACs, with final methodology determined during the Proposed Development's final design phase. The PDE for Interconnector Cables is provided in Table 3.8.

Table 3.8: PDE for Interconnector Cables

Parameter	Maximum Design
Maximum number of Interconnector Cables	3
Maximum total cable length (km)	36
Maximum external cable diameter (mm)	250
Cable burial methodology	Lay then burial and/or simultaneous lay and burial. Ploughing/jetting/cutting Multiple installation techniques to be achieved using hybrid installation equipment.
Target burial depth (m)	1.5 with greater burial depths targeted in specific areas (e.g. in areas of increased shipping density)
Minimum target burial depth (m)	0.5 (subject to CBRA)
Maximum width of cable trench (m)	6
Maximum width of seabed affected from installation tool per cable (m)	25

External Cable Protection

3.3.43 Where minimum target cable burial depth cannot be achieved, external cable protection methods will be employed to restrict movement and prevent exposure over the lifetime of the Proposed Development. This will protect cables from activities such as fishing, anchor placement or dropped objects, limit effect of heat and/or electromagnetic fields, and safeguard other seabed users from potential hazards posed by the cables. External cable protection systems include PU, PE, steel, or iron CPS, rock protection, grout bags, concrete mattresses, and/or protective sleeves.

3.3.44 The final solution(s) chosen at final design stage (post-consent) will be dependent upon seabed conditions and any potential interactions with human activities which may occur within the Proposed Development (for example, areas where intensive bottom-trawl fishing). Table 3.9 presents the PDE for external cable protection for IACs and Interconnector Cables.

Table 3.9: PDE for External Cable Protection for IACs and Interconnector Cables

Parameter	Maximum Design	
	IACs	Interconnector Cables
Type	CPS (typically made of cast-iron, steel, PU/PE, e.g. articulated split pipes, uraduct or protective sleeves), rock placement, grout bags, rock berms, rock bags, and concrete mattresses	
Maximum cable protection height (m) above seabed	2	
Maximum cable protection width (m)	10	
Maximum percentage of cables which may require cable protection (%)	50	
Maximum length of cables which may require cable protection (m)	75,500	18,000
Maximum total cable protection footprint area for Array Area (m^2)	755,000	180,000
Maximum total cable protection volume for Array Area (m^3)	1,510,000	360,000

Rock Placement and Rock/Grout Bags

3.3.45 Rock placement may be utilised as a form of external cable protection for IACs and Interconnector Cables and at cable crossings (see Paragraph 3.3.50). Rock is placed on top of cables either by creating a berm or using rock bags (Figure 3.8).

3.3.46 Rock berm creation will utilise a vessel with equipment such as a 'fall pipe' so that rock can be placed close to the seabed. Rock may be placed to a maximum height of 2 m and width of 10 m (see Table 3.9 for cable protection). The berm created will be designed to provide protection from anchor strike and anchor dragging, and to reduce risk of snagging by towed fishing gear as far as practicable in line with best practice guidance. Depending on expected scour, the cross-section of the berm may vary, and the length of the berm will be dependent on the length of the cable which requires protection.

3.3.47 Alternatively, pre-filled rock/grout bags may be used which will be placed above the IACs and Interconnector Cables or cable crossings using installation beams. Rock bags consist of various sized rocks contained within a rope or wire net which are lowered to the seabed and deployed into the correct position (similar to installation of concrete mattresses, see Paragraphs 3.3.48 to 3.3.49). The number of rock bags which may be required will be dependent on the length of cable which requires protection. Grout bags are similar to rock bags but filled with grout.

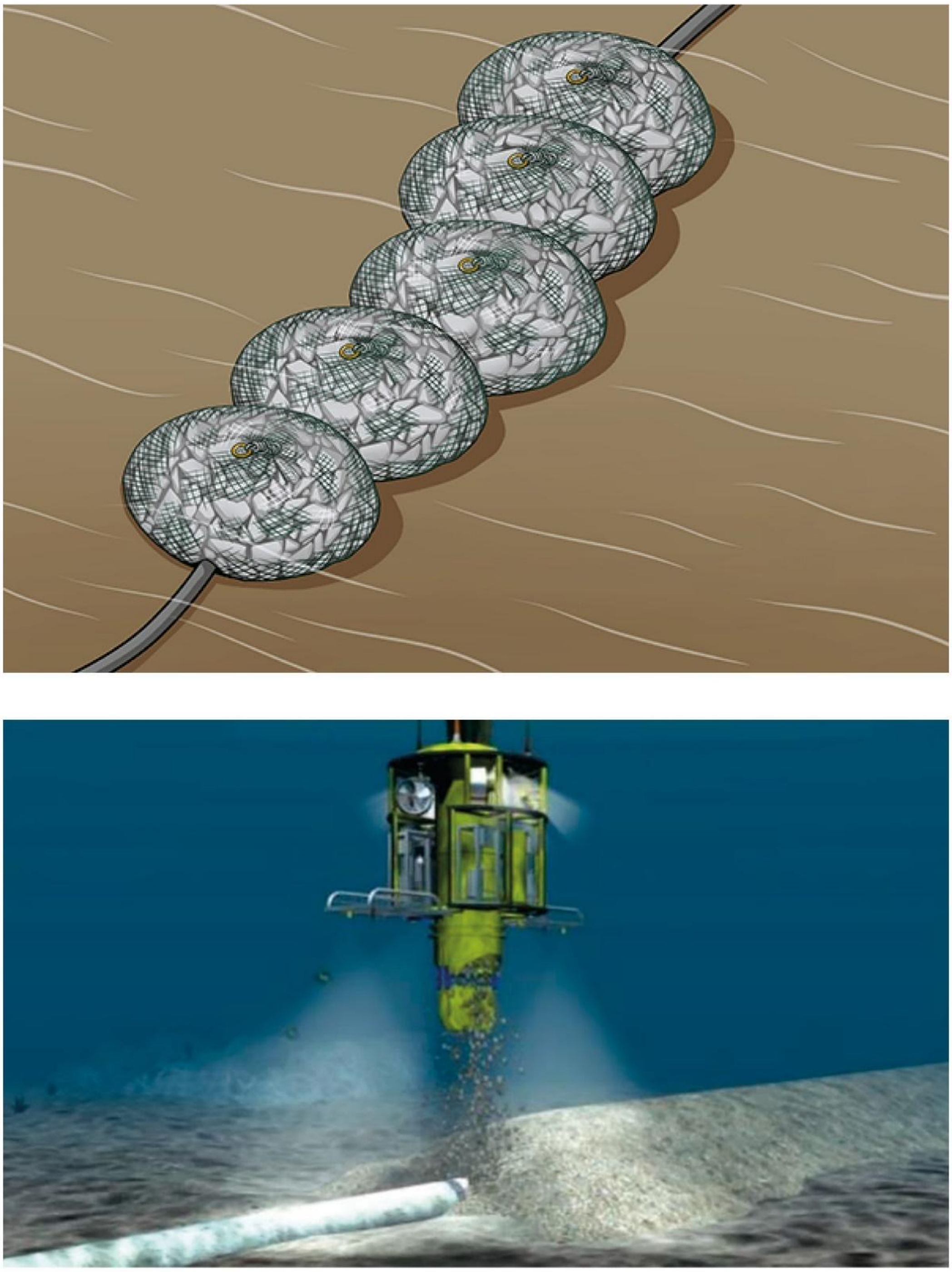


Figure 3.8: Rock Cable Protection Methods (Top: Rock Bags, Bottom: Rock Placement)

Concrete Mattressing

3.3.48 Concrete mattresses, comprising high strength concrete blocks and ultraviolet (UV) stabilised polypropylene rope, may be used as a means of external cable protection for IACs and Interconnector Cables and at cable crossings (Paragraph 3.3.50). The size, density, and shape of units may vary (within the parameters presented in Table 3.9 for cable protection and Table 3.10 for cable crossings), for example, by tapering edges of units for use in high current environments, or using denser concrete, so that they are engineered for and bespoke to the locality in which they are installed.

3.3.49 Concrete mattresses are installed above the cables using a vessel and free-swimming installation frame. The mattresses are lowered to the seabed and the installation frame is released in a controlled manner once in the correct position to deploy the mattress on the seabed. This installation process is repeated for each mattress along the length of cable that requires external protection. Dependant on expected scour, mattresses may be gradually layered in a stepped formation on top of each other.

Cable Crossings

3.3.50 Up to nine IAC crossings and up to three Interconnector Cable crossings may be required across the Array Area. The IAC crossings considered at this stage are based on crossings with a third-party subsea cable, while the Interconnector Cable crossings are based on crossings with the IAC cables. Cable crossings may comprise several different methods as presented in Table 3.10, and additional cable protection will be installed at cable crossings. Table 3.10 presents the PDE for cable crossings, and accounts for additional protection required.

Table 3.10: PDE for Cable Crossing for IACs and Interconnector Cables

Parameter	Maximum Design	
	IACs	Interconnector Cables
Maximum number of crossings	9	3
Crossing material/method	Rock placement, grout/rock bags, rock berms, concrete bridges and concrete mattresses, and CPS (typically made of cast-iron, steel, PU/PE, e.g. articulated split pipes, uraduct or protective sleeves)	
Maximum height of crossing above seabed (m)	2.5	
Maximum width of crossing (m)	9	
Maximum length of each crossing (m)	500	
Maximum total length of crossings across the Array Area (m)	4,500	1,500
Maximum total area of crossings (m^2)	40,500	13,500
Maximum volume of protection material (per crossing) (m^3)	11,250	
Maximum total volume of crossing protection across the Array Area (m^3)	101,250	33,750

3.4 Offshore Transmission Assets

Offshore Substation Platforms

3.4.1 OSPs are required to receive electricity generated by the Wind Turbines and transform it to a higher voltage to allow the electricity to be transmitted efficiently to shore. The Proposed Development may require up to three OSPs which will be located within the Array Area.

3.4.2 The Proposed Development will use High Voltage Alternating Current (HVAC) transmission technology. The final electrical layout for the Proposed Development will determine the final number, location(s) and specifications of each OSP, and will be confirmed during the Proposed Development detailed design phase (post application submission). All OSPs will be appropriately marked for aviation and navigation purposes, for example using necessary lighting and paint finish. An illustration detailing a typical OSP design is provided in Figure 3.9.

3.4.3 The PDE for the OSP topsides and foundations is presented in the following subsections.

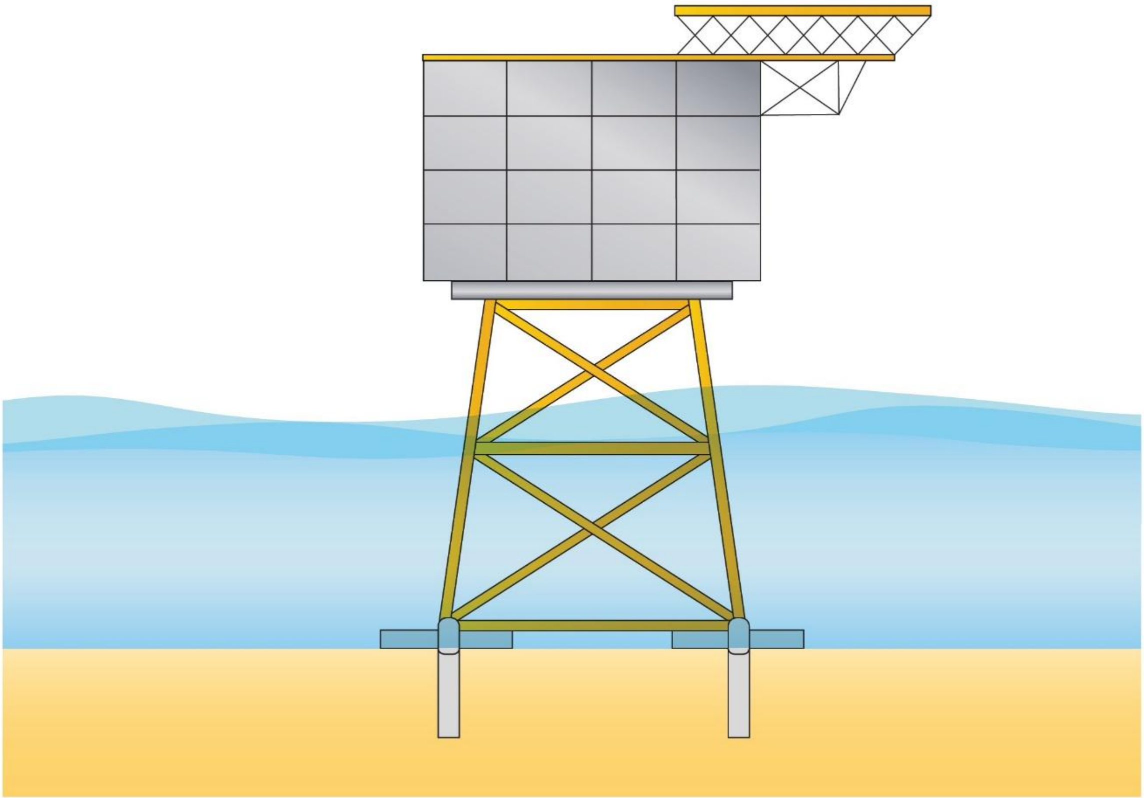


Figure 3.9: Illustrative OSP on a Jacket Foundation

Offshore Platform Topsides

3.4.4 Up to three OSP topsides will be installed with maximum dimensions of up to 100 m (length) by 80 m (width) and up to approximately 60 m in height (above LAT). This height excludes the lightning protection. The three options for the OSP topsides are presented Table 3.11.

Table 3.11: PDE for the OSP Topside Options

Parameter	Maximum Design		
	Option 1	Option 2	Option 3
Maximum number of OSPs	2	1	3
Maximum length of topside (m)	80	100	50
Maximum width of topside (m)	60	80	40
Maximum height of main structure above LAT (excluding lightning protection) (m)	60	60	60
Maximum height of lightning protection above LAT (m)	70	70	70

Offshore Platform Foundations

3.4.5 Each OSP will sit on a piled jacket foundation, with up to eight legs for the foundation(s). It is anticipated that foundations will be constructed onshore before specialist vessels are used to transport and install the foundations within the Array Area.

3.4.6 The diameters of the piles associated with piled jacket foundations are lower than monopile foundations, however similar technology may be utilised for their installation: hydraulic hammers, vibration, drilling into the seabed. The installation of foundations for the OSP(s) will be undertaken using one of two primary methods, either piling, or drive-drill-drive. The choice of method will depend on factors such as seabed conditions and the dimensions of the piles. Piling typically involves the use of hydraulic hammers or vibration techniques, while the drive-drill-drive method incorporates piling, followed by drilling to penetrate hard seabed layers and potentially further piling to achieve the required depth.

3.4.7 For OSP Option 1 (two OSPs), this results in a maximum of 18 piles required per foundation, and up to 36 piles will require piling for the two OSPs. For OSP Option 2 (one OSP), a maximum of 18 piles will be required for the foundation of a single OSP. For OSP Option 3 (three OSPs), there will be eight piles per OSP foundation, with up to 24 piles for the three OSPs (Table 3.12).

3.4.8 Scour protection details for OSPs are the same as for the wind turbine foundations, presented in Paragraphs 3.3.27 to 3.3.29.

3.4.9 It is expected that one vessel will be utilised to conduct piling/drilling events for OSP foundations, using a maximum hammer energy of 4,500 kJ. Up to two piling operations may occur simultaneously at Wind Turbine or OSP locations; concurrent piling of OSP foundations is possible in the MDS where two or three OSPs are considered.

Table 3.12: PDE for the OSP Fixed Jacket Foundations

Parameter	Maximum Design		
	Option 1 – 6 leg jacket	Option 2 – 8 leg jacket	Option 3 – 4 leg jacket
Maximum number of OSPs	2	1	3
Maximum number of legs per foundation	6	6[4]	4
Maximum leg diameter (m)	3	3.5	3
Maximum number of driven piles per leg	3	3[4]	2
Maximum number of driven piles per platform foundation	18	18[4]	8
Maximum jacket leg spacing (at seabed) (m)	48 x 48	48 x 48	48 x 48
Maximum jacket leg spacing (at surface) (m)	25 x 30	36 x 54	25 x 30
Maximum driven pile diameter (m)	4.5		
Maximum driven pile length (m)	90		
Maximum driven pile penetration depth (m)	70		
Maximum dimensions of mud mats (if used) (m)	20 x 20		
Maximum seabed footprint per jacket foundation (m^2)	2,400	3,200	1,600
Maximum seabed footprint for the Proposed Development (m^2)	4,800	3,200	4,800
Maximum total number of driven piles requiring piling (all platforms)	36	18[4]	24
Maximum hammer energy (kJ)	4,500		
Scour protection type	Rock		
Maximum height of scour protection (m)	1		
Maximum diameter of scour protection per jacket leg (including pile/anchor) (m)	40.0		29.0
Maximum area of scour protection per foundation (excluding pile area) (m^2)	7,500	10,000	5,000
Maximum volume of scour protection per foundation (m^3)	7,500	10,000	5,000
Maximum volume of scour protection for Proposed Development (m^3)	15,000	10,000	15,000

[4] The maximum design scenario assumes six legs, each supported by three piles, resulting in a total of 18 piles. An alternative configuration of eight legs may be considered only if it facilitates a reduction in the overall number of piles, for example, eight legs with two piles each, totalling 16 piles.

Offshore Export Cables

3.4.10 To transfer the energy from the OSPs located in the Array Area to Landfall (and to subsequent onshore transmission infrastructure), up to three HVAC cable circuits may be laid within the Export Cable Corridor (see Figure 3.1) with a maximum cable length of 70 km each. Landfall is located in Benholm, Aberdeenshire and a trenchless technique (e.g. HDD) will be used to bring the Offshore Export Cables ashore (see Figure 3.10 and Section 3.6). In the nearshore area the Export Cable Corridor narrows to align with Landfall. At the Array Area, the Export Cable Corridor runs along its western edge.

Project Title:	Bowdun Offshore Wind Farm	Figure Title:	Location of Proposed Development Export Cable Corridor and Landfall at Haughs Bay

LEGEND

Export Cable Corridor

0 0.5 1 nm
0 1 2 km

Geodetic Information:
Datum: ETRS 1989
Projection: ETRS 1989 UTM Zone 30N

Data Sources: Client,
© Crown copyright and database rights 2025
Ordnance Survey AC0000808122

Service Layer Credits: World Topographic Map: Esri, HERE, Garmin, FAO, NOAA, USGS

VER	DATE	DETAILS	BY	CHK
00	19/06/25	First Issue	MJ	CR
01	10/10/25	Revision	MJ	CR
-	-	-	-	-
-	-	-	-	-

Drawing Number:
EOR0770A-ES-MISC-005-01

Figure 3.10: Location of Proposed Development Export Cable Corridor and Landfall at Benholm, Aberdeenshire

3.4.11 As with the IACs and Interconnector Cables, where practicable the Offshore Export Cables will be buried to an appropriate target burial depth to ensure they are protected, to reduce the need for cable protection and to reduce interaction with other sea users.

3.4.12 The ability to bury cables will be largely dependent on sediment types and ground conditions. Cable burial depths will be informed by a CBRA, but based upon current understanding, they will be installed to a target burial depth of 1.5 m (subject to further design), with greater burial depths targeted in specific areas, e.g. in areas of increased commercial fisheries and shipping density.

3.4.13 Installation of the Offshore Export Cables may be through a range of methods including pre-lay plough, plough, trenching, cutting and/or jetting techniques. Considering the anticipated length of the Offshore Export Cables, and seabed conditions, a combination of burial and external cable protection methods will be required.

3.4.14 As previously mentioned in Paragraphs 3.3.43 to 3.3.49, whenever the minimum target cable burial depth is not achievable, external cable protection methods will be implemented to restrict any movement and prevent exposure over the lifetime of the Proposed Development. This will limit the effects of heat and/or electromagnetic fields and help to protect against human activities such as fishing, anchor placement or dropped objects. Cable Protection Systems that could be used by the Applicant include concrete masses, rock placement, cast iron shells, or PU/PE sleeving. The Applicant will decide the final solution(s) at final design stage (post-consent) which will be dependent on seabed conditions as well as any potential interactions with human activities that may occur within the Proposed Development.

3.4.15 The PDE for the Offshore Export Cables is presented in Table 3.13, and the PDE for the external cable protection for the Offshore Export Cables is presented in Table 3.14.

3.4.16 Up to six Offshore Export Cable crossings may be installed along the Export Cable Corridor. Cable crossings may comprise several different methods as presented in Table 3.15, and additional cable protection will be installed at cable crossings. Table 3.15 presents the PDE for cable crossings, and accounts for additional protection required.

Table 3.13: PDE for the Offshore Export Cables

Parameter	Maximum Design
Export cable voltage (kV)	220-275
HVAC/HVDC	HVAC
Maximum total cable length (km)	210
Maximum external cable diameter (mm)	300
Cable burial methodology	Lay then burial and/or simultaneous lay and burial. Ploughing/jetting/cutting Multiple installation techniques to be achieved using hybrid installation equipment. A trenchless technique will be used at Landfall (e.g. HDD)
Target burial depth (m)	1.5 (subject to CBRA), with greater burial depths targeted in specific areas (e.g. in areas of increased shipping density)
Minimum target burial depth (m)	0.5 (subject to CBRA)
Maximum width of cable trench (m)	6
Maximum width of seabed affected from installation tool per cable (m)	25

Table 3.14: PDE for the External Cable Protection for the Offshore Export Cables

Parameter	Maximum Design
Type	CPS (typically made of cast-iron, stell, PU/PE, e.g. articulated split pipes, uraduct or protective sleeves), rock placement, grout or rock bags, rock berms, and concrete mattresses
Maximum cable protection height (m)	2
Maximum cable protection width (m)	10
Maximum percentage of cable which may require cable protection (%)	50
Maximum length of cables which may require cable protection (m)	105,000
Maximum total cable protection footprint area for Proposed Development (m^2)	1,050,000
Maximum total cable protection volume for Proposed Development (m^3)	2,100,000

Table 3.15: PDE for Cable Crossing for the Offshore Export Cables

Parameter	Maximum Design
Maximum number of crossings	6
Crossing material/method	CPS (typically made of cast-iron, stell, PU/PE, e.g. articulated split pipes, uraduct or protective sleeves), rock placement, grout bags, rock berms, rock bags, and concrete bridges and concrete mattresses
Maximum height of crossing (m)	2.5
Maximum width of crossing (m)	9
Maximum length of each crossing (m)	500
Maximum total length of crossings along the Export Cable Corridor (m)	3,000
Maximum total area of crossings (m^2)	27,000
Maximum volume of protection material (per crossing) (m^3)	11,250
Maximum total volume of crossing protection along the Export Cable Corridor (m^3)	67,500

3.4.17 As mentioned in Paragraph 3.4.10, Landfall is located in Benholm, Aberdeenshire and trenchless technology will be used to bring the Offshore Export Cables ashore. The drilling required for the trenchless installation method will commence from above Mean High Water Springs (MHWS), span under the Intertidal Area and will punch out below MLWS. The PDE for the Offshore Export Cables at Landfall is presented in Table 3.16, with further detail on installation methodologies provided in in Section 3.6. The inclusion of up to four HDD cable ducts, despite only three export cables being proposed, allows for operational flexibility and risk management during installation and future maintenance.

Table 3.16: PDE for the Offshore Export Cables at Landfall

Parameter	Maximum Design
Type	Trenchless technology, e.g. HDD, pipe jacking tunnel
Corridor width (m)	80
Maximum number of HDD cable ducts	4
Maximum HDD borehole diameter (m)	2.2
Indicative length of cable ducts (m)	755
HDD length in the Intertidal Area (m)	600
Minimum HDD burial depth in the Intertidal Area (m)	7
Maximum number of HDD pits	4
Indicative dimensions of exit pits (m)	2.2 x 50

Parameter	Maximum Design
Method of excavation at exit pits	The transition profile of the HDD duct onto the seabed would be determined during the detailed design phase. In a scenario where a levelled transition cannot be achieved onto the seabed, excavation may be required. Excavation methods include the use of: • Mass flow excavator; • Dredge dump; and • Cutter suction dredger. These methods could be deployed from spud leg, anchored barge or jack-up vessel. Excavated material will be placed with the Site Boundary.
Total indicative volumes of excavated material at exit pits (m^3)	8,400

3.5 Site Preparation Activities

3.5.1 Prior to the installation of Offshore Infrastructure, it is likely that seabed preparation will be required, including pre-sweeping, seabed-levelling, sandwave clearance, boulder clearance, pre-cut trenching and the removal or avoidance of debris (e.g. fishing nets, out of service utilities, lost anchors, or Unexploded Ordnance (UXO)). Excavation may also be required to allow access and removal where debris is found to be present below the seabed surface. Furthermore, pre- and post-installation of rock berms, concrete mattresses and other CPSs (e.g. steel/rubber/PE/PU sleeves or tubes) may be needed in different configurations for installation of cable systems in locations where the cable(s) routing cannot avoid steep slopes or need to cross channels in the Array Area or Export Cable Corridor.

3.5.2 Site preparation activities will continue throughout the construction phase as required and, therefore, these activities can be undertaken at any point within the construction programme (see Paragraphs 3.6.45 to 3.6.46).

Pre-Construction Surveys

3.5.3 Pre-construction surveys, including geophysical and geotechnical surveys, will be carried out to provide further information on:

- seabed conditions and morphology;
- soil conditions and properties;
- presence or absence of any potential obstructions or hazards; and
- to inform progression of design for the Proposed Development.

3.5.4 Geophysical surveys will be undertaken within the Site Boundary to provide further information on UXO, bedforms and mapping of boulders, bathymetry, topography and sub-surface layers. Geophysical survey techniques to be employed include Multibeam Echosounder (MBES), magnetometer, Side-Scan Sonar (SSS), Sub-Bottom Profiler (SBP) and Ultra-High Resolution Seismic (UHRS).

3.5.5 Geotechnical surveys will be carried out at specific locations within the Site Boundary and will employ techniques such as Cone Penetration Tests (CPTs), vibrocores, box cores, piston cores and boreholes.

Clearance of Unexploded Ordnance

3.5.6 UXO may be present within the Array Area and Export Cable Corridor (originating from Word War I or World War II). Due to the health and safety risks posed by UXO, and potential interactions with planned locations of installed infrastructure and vessel activities, it is necessary for the potential presence of UXOs to be surveyed and if identified, managed carefully before the construction phase and installation of Offshore Infrastructure commences.

3.5.7 A desk-based study of the Proposed Development (Volume 3, Technical Appendix 19.2: Unexploded Ordnance Technical Report) reviewed the relevant military history in the vicinity of the Proposed Development and the likelihood of encountering UXO. Based on known military activity, the desk-based study concluded that there was a varying low-moderate and moderate risk from encountering UXO within the Site Boundary. Further assessment of UXOs has been undertaken within the relevant topic chapters (Volume 2, Chapters 7 to 23) on the basis of the desk-based study (Volume 3, Technical Appendix 19.2: Unexploded Ordnance Technical Report).

3.5.8 Methodologies considered within the PDE to avoid/clear UXOs are as follows:

- avoid and leave *in situ*;
- micrositing of Offshore Infrastructure to avoid UXO;
- relocation of UXO to avoid detonation;
- low order clearance technique (e.g. deflagration); and
- high order detonation (with associated mitigation measures).

3.5.9 Due to the health and safety risks that UXOs pose, the Applicant would seek to either avoid UXOs entirely, avoid UXOs via micrositing, or relocate UXO where practicable. If methods cannot be employed to avoid or relocate UXOs, a specialist contractor will clear UXOs in advance of construction taking place. The preferred clearance method for UXO is use of a low order technique with a single donor charge of 0.25 kg Net Explosive Quantity (NEQ) for each clearance event. Up to 0.5 kg NEQ clearance shot will be required for neutralisation of residual explosive material at each location. Detailed design work would be required to confirm planned locations of infrastructure, prior to conducting any UXO surveys. The Applicant has estimated that up to 40 UXOs may require clearance based upon the desk-based study. As a risk remains that unintended high order detonation may occur, all of the clearance events have been assumed to have the potential to result in high order detonation, as this would result in the greatest impact (see Volume 2, Chapter 10; Marine Mammals and Volume 3, Chapter 10.4 Subsea Noise Technical Report).

3.5.10 Table 3.17 presents the PDE for UXO clearance.

Table 3.17: PDE for Unexploded Ordnance Parameters

Parameter	Maximum Design
Theoretical maximum weight anticipated to be encountered (kg)	1,170
Maximum realistic charge weight (kg)	254
Maximum estimated number of UXOs to be identified	40
Maximum estimated number of UXOs to be cleared	40
Maximum number of detonation activities occurring within 24 hours	2
Maximum total duration of UXO clearance activities (days)	40

Sandwave Clearance

3.5.11 Prior to the installation of Offshore Infrastructure, existing sandwaves may need to be cleared in some areas of the Proposed Development. There are two main reasons for undertaking sandwave clearance:

- To provide a relatively flat seabed surface for cable installation and so that cable burial tools can work effectively: if cables are installed up or down a slope over a certain angle, or where the cable burial tool is working on a camber, the ability to meet target burial depths may be impacted.
- In order for cables to be buried to the target burial depth and remain buried for the operational lifetime of the Proposed Development (30 years): as sandwaves are generally mobile in nature, the cable must be buried beneath the level where natural sandwave movement could uncover it. Therefore, for this to be achieved, mobile sediments may need to be removed before cables are installed and buried.

3.5.12 Seabed morphology varies across the Array Area. With north-east to south-west oriented sandwaves are located in southern–central and eastern parts of the area, megaripples and ripples dominating the central, north–eastern, and north–western zones (see Volume 3, Technical Appendix 7.1: Physical Processes Baseline Environment). Along the Export Cable Corridor there are megaripples and sandwaves present in many areas along the route, with heights in excess of 6 m in place.

3.5.13 Sandwave clearance is likely to be required in specific discrete areas of the Proposed Development (e.g. along IACs, Interconnector Cables, and Offshore Export Cables) and could occur throughout the construction phase.

3.5.14 Sandwave clearance methods could include mass flow excavator or the use of a trailing suction hopper dredger, or a combination of both.

3.5.15 Excavated material will be preferentially deposited within the Site Boundary and as close as practicable to the excavation location. This approach aims to retain a broadly similar composition of sediment within the disposal area.

3.5.16 Table 3.18 presents the PDE for sandwave clearance. A geophysical survey campaign will be completed prior to construction which will allow the final parameters for sandwave clearance to be defined.

Table 3.18: PDE for Sandwave Clearance

Parameter	Maximum Design
Array Area	
Maximum width of sandwave clearance along IACs and Interconnector Cables (m)	58.6
Maximum percentage of total length of IACs and Interconnector Cables requiring sandwave clearance (%)	0.56
Maximum area of sandwave clearance along IACs (m^2)	49,552
Maximum volume of sandwave clearance along IACs (m^3)	197,955
Maximum area of sandwave clearance along Interconnector Cables (m^2)	11,814
Maximum volume of sandwave clearance along Interconnector Cables (m^3)	47,191
Maximum area of sandwave clearance for fixed foundations (m^2)	172,220
Maximum volume of sandwave clearance for fixed foundations (m^3)	724,273
Maximum area of sandwave clearance for OSP scour protection (m^2)	24,359
Maximum volume of sandwave clearance for OSP scour protection (m^3)	136,412
Export Cable Corridor	
Maximum width of sandwave clearance along Offshore Export Cables (m)	58.6
Maximum percentage of total length of Offshore Export Cables requiring sandwave clearance (%)	4.95
Maximum area of sandwave clearance along Offshore Export Cables (m^2)	609,147
Maximum volume of sandwave clearance along Offshore Export Cables (m^3)	3,411,223

Boulder Clearance

3.5.17 Boulder clearance will be required in some areas of the Proposed Development prior to installation of Offshore Infrastructure, in particular, along IACs and Offshore Export Cables. A boulder is defined as being over 256 mm (Wentworth Scale) in diameter and/or length.

3.5.18 Boulder clearance is required to aid cable installation and increase the success rate for achieving minimum target burial depth during cable burial, therefore, reducing the risk of further cables burial works and/or the need for cable protection. Boulder clearance also reduces the risk of cable damage during installation and subsequent burial. The PDE for boulder clearance for the Proposed Development is presented in Table 3.19.

3.5.19 Boulders may be cleared using one or a combination of the following:

- a boulder grabber or Remote Operated Vehicles (ROV), where boulders would be picked up from the seabed and relocated to designated areas within the Site Boundary;
- a displacement plough to clear boulders from the cable route creating a path for cable installation; and/or
- pre-lay grapnel runs used to prepare the seabed before cable installation.

3.5.20 Geophysical and pre-construction surveys, and the parameters of any boulders present (e.g. size, density and location of boulders), will inform the boulder clearance methodology to be used.

Table 3.19: PDE for Boulder Clearance

Parameter	Maximum Design
Maximum width of boulder clearance along IACs, Interconnector Cables, and Offshore Export Cables (m)	25
Maximum area of boulder clearance along IACs (m^2)	98,150
Maximum percentage of total length of IACs and Interconnector Cables requiring boulder clearance (%)	2.6
Maximum area of boulder clearance along Interconnector Cables (m^2)	23,400
Maximum area of boulder clearance along Offshore Export Cables (m^2)	254,289
Maximum percentage of total length of Offshore Export Cables requiring boulder clearance (%)	4.9

Vessels for Site Preparation Activities

3.5.21 The PDE for vessels to be used during site preparation activities is presented in Table 3.20.

Table 3.20: PDE for Vessels for Site Preparation Activities

Parameter	Maximum Design	
	Maximum Total Number of Vessels on Site at any One Time	**Total Movements (Return Trips Across Site Preparation Activities)**
Export Cable Corridor		
Geophysical/geotechnical survey vessel	7	55
Boulder/UXO clearance vessel*	2	10
Array Area		
Geophysical/geotechnical survey vessel	7	55
Boulder/UXO clearance vessel*	2	20
Total	18	140

*Sandwave clearance will be during construction rather than site preparation.

3.6 Construction Phase

Methodology

3.6.1 Construction of the Proposed Development is expected to take place over a period of five years, following pre-construction surveys, and will proceed in accordance with the indicative construction sequence outlined below:

- Step 1 – Offshore Export Cables installation at Landfall ;
- Step 2 – Wind Turbine fixed foundation transport and installation;
- Step 3 – Offshore Export Cables installation offshore, including cable burial and/or protection, where required;
- Step 4 – OSP topside and fixed foundation installation and commissioning;
- Step 5 – Interconnector Cable and IAC Installation, including cable burial and/or protection, where required; and
- Step 6 – Wind Turbine transport, installation and commissioning.

3.6.2 The following subsections summarise these steps.

Step 1 – Offshore Export Cables Landfall installation

3.6.3 Figure 3.10 shows the Proposed Development Export Cable Corridor as it reaches Landfall at Benholm, Aberdeenshire.

3.6.4 Installation parameters for the Offshore Export Cable at Landfall are presented in Table 3.16 Works landward of MLWS are described and assessed in the Onshore EIA Report (BOWFL, 2025), and are assessed cumulatively with the Proposed Development in this Offshore EIA Report.

3.6.5 It is proposed that the Offshore Export Cables are installed in the Intertidal Area using trenchless technology (Figure 3.11), such as HDD. HDD involves drilling a hole (or holes) along an underground pathway from one point to another, through which the Offshore Export Cables are installed, without the need to excavate an open trench. The drilling installation will commence from above MHWS, with the exit point (punch out location) located seaward of MLWS. As such, no above-ground construction works are planned to take place in Landfall.

3.6.6 The HDD works comprise of the following main stages:

1) A pilot hole is drilled from onshore.
2) Once the pilot hole is completed, the reaming process will commence, increasing the diameter of the pilot hole to accommodate the safe installation of HDD duct. The reaming process will continue back and forth for a number of passes to achieve a minimum bore diameter. During the drilling procedure, drilling fluid (such as Bentonite) is continuously pumped to the drill head to act as a lubricant. Solids are removed from the returning fluid, and the spoil is transported off site.
3) A spud leg, anchored barge or jack-up vessel will be used at the HDD exit point to create an HDD exit punch out. The transition profile of the HDD duct onto the seabed will be determined during the detailed design

phase. In a scenario where levelled transition cannot be achieved onto the seabed, excavation could be required. Excavation methods would include the use of mass flow excavator, dredge pump or cutter suction dredger.

4) The last forward HDD reamer exits the seabed at the HDD exit punch out.
5) The HDD reamer is then disconnected from the drill pipe and recovered.
6) The High-Density Polyethylene liner pipe will be pre-assembled and then floated in, connected to the drill pipe, and pulled onshore from the offshore end through the pre-drilled bore into position.
7) Steps 1 to 6 are then repeated for all the Offshore Export Cables.
8) Trenches are then excavated from the HDD entry points above the MHWS to the Transition Joint Bay (TJB) and ducts installed and backfilled (covered as part of the onshore submission activities).
9) HDD construction equipment and plant is then demobilised from site.
10) The ducts are then proved ready for cable pull in and messenger wires are installed.
11) Offshore Export Cables will then be installed in the ducts by pulling them from the offshore delivery vessel (below MLWS) through the installed ducts to the TJBs (at MHWS).

3.6.7 HDD drilling activities may be required to operate continuously over a 24-hour period until each bore is complete. Drilling may be carried out concurrently to accelerate the construction works programme. This will be subject to further construction planning and availability of drilling rigs.

3.6.8 Pull in techniques for HDD installation include direct pull in, where the cable vessel will sit a short stand-off distance from the HDD exit point, and the cable is pulled directly from the vessel. The other technique is floating pull in, where the vessel will stand-off at a suitable water depth for its safe operation and float the cable toward the duct, with a second vessel assisting located above the HDD exit point to guide the cable though the duct.

3.6.9 Bentonite comprises 95% water and 5% bentonite clay which is a non-toxic, natural substance. Bentonite drilling fluid is non-toxic and is commonly used offshore. Every reasonable endeavour will be made to minimise the risk of a breakout (loss of drilling fluid to the surface). The finalised EMP will provide information on the procedure for managing a breakout of Bentonite under the water.

3.6.10 As part of the detailed design work to inform the construction of the Offshore Export Cables at Landfall, the potential risks relating to cable exposure due to coastal recession and beach lowering will be considered in detail, including the effects of climate change over the O&M phase of the Proposed Development. Minimum trenchless burial depths in the Intertidal Area are provided in Table 3.16, but this is subject to further refinement post consent.

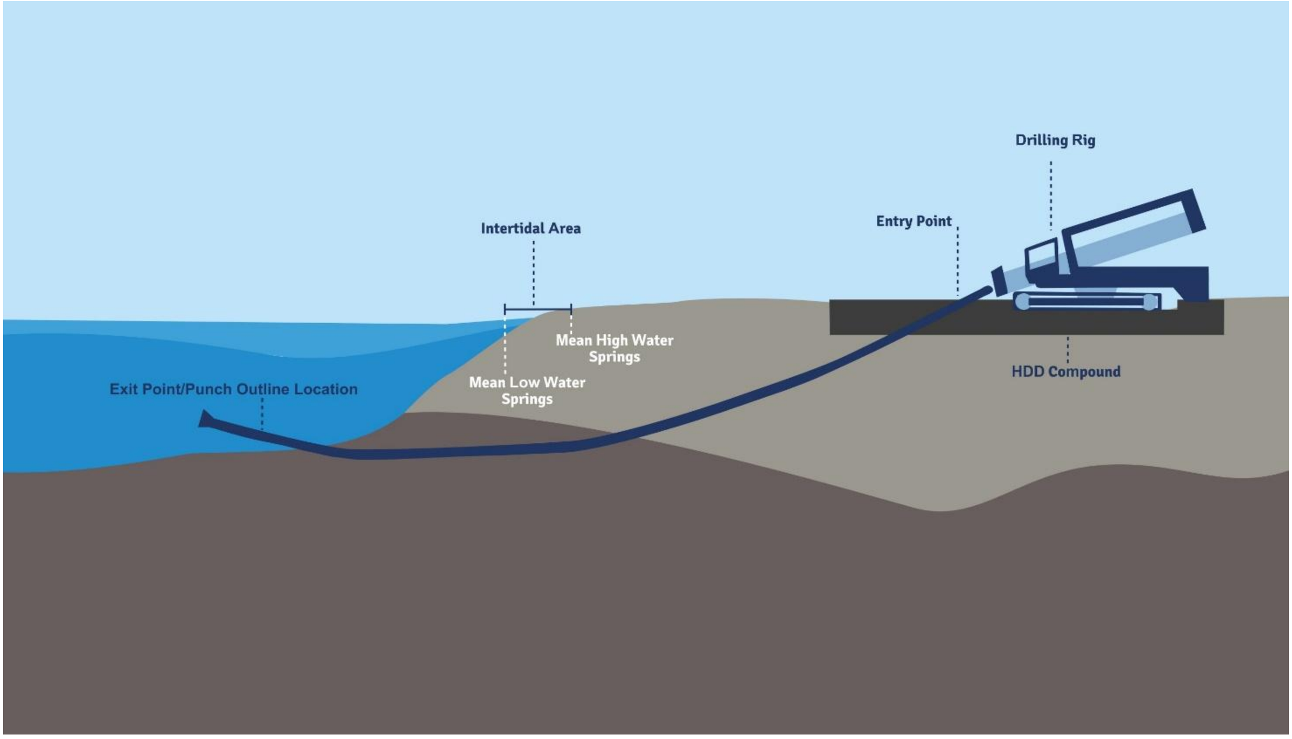


Figure 3.11: Cross Section Showing Trenchless Technology at Landfall

Step 2 – Wind Turbine Fixed Foundation Transport and Installation

3.6.11 The Proposed Development will use fixed-bottom Wind Turbine foundations. Wind Turbine foundations will be transported to the Array Area by vessels. Paragraphs 3.6.38 to 3.6.40 present further details of vessels involved in installation activities within the Proposed Development.

3.6.12 Table 3.21 presents the piling characteristics required for the installation of the Wind Turbine foundations. It is anticipated that a crane will be used to lower the pile to the seabed and will be kept in position using a pile gripper or a pile installation frame, which may be temporarily placed on the seabed and then moved to the next location once the piles are installed. Piles will be installed into the seabed using a hammer.

3.6.13 Detailed geotechnical data from the Array Area will inform a driveability assessment to determine the optimal hammer energy required at each location. This will ensure efficient installation while minimising energy use. It is anticipated that the maximum hammer energy will only be required at selected locations. Up to two piling operations may occur simultaneously at Wind Turbine or OSP locations; concurrent piling of OSP foundations is possible in the PDE where two or three OSPs are considered.

3.6.14 Where jacket foundations are used, piles may be pre-installed in advance of jacket installation. Jackets will then be transported to site by barge or heavy transport vessel, lowered onto the pre-installed piles using a crane, and secured in place using grout.

3.6.15 For suction bucket jacket foundations, the structure will be lowered to the seabed by crane and installed using suction-assisted penetration. This method involves pumping water out of the buckets to create a pressure differential, drawing the foundation into the seabed.

3.6.16 If scour protection is required, it will generally be installed prior to foundation installation. However, in some cases, it may be installed following foundation placement, depending on site-specific conditions and installation sequencing.

Table 3.21: PDE for Wind Turbine Foundations – Driven Piling Characteristics

Parameter	Maximum Design	
	15 MW Wind Turbines	**25 MW Wind Turbines**
Maximum number of piles requiring piling	268	160
Maximum hammer energy (kJ)	6,250	
Soft start energy (% of maximum hammer energy)	15	
Maximum soft start duration (minutes)	20	
Maximum duration of piling per pile (hours)	12.4	15.2
Maximum number of piles installed over 24 hours	4	
Estimated average number of piles installed over 24 hours	2	
Maximum duration of piling per day over construction phase (hours)	22.0	
Maximum total number of days when piling may occur over construction phase	268	160
Maximum number of concurrent piling events	2	
Minimum distance between concurrent piling events (km)	1	
Maximum distance between concurrent piling events (km)	20	

3.6.17 If hard ground is encountered which makes pile driving unsuitable, a combination of drill and driven installation methods may be required. In this case, a drill would be used after initial piling to remove the seabed material inside the pile and continue to installation to the target penetration depth. Drilling characteristics are presented in Table 3.22.

3.6.18 Seabed material (drill arisings) will be released as a result of drilling activities. This material will be deposited adjacent to each drilled foundation location within the Array Area (see Volume 2, Chapter 7: Physical Processes for the assessment of drill arisings).

3.6.19 As shown in Figure 3.3 and Figure 3.4, there are a number of spare Wind Turbine locations within the Array Area. These spare locations have been identified in case seabed conditions are not suitable for Wind Turbine installation. These spare locations are included within the PDE and assessed in this application, but will only be used if required as part of the final design, but not considered in the confirmed final layout post-consent.

Table 3.22: PDE for Wind Turbine Foundations – Drilling Characteristics

Parameter	Maximum Design	
	15 MW Wind Turbines	25 MW Wind Turbines
Maximum number of piles requiring drilling over the Proposed Development	268	160
Maximum (%) of all piles requiring drilling over the Proposed Development	100	
Maximum drilling rate (m/hour)	2	
Maximum drilling depth per pile (m)	32.5	40
Maximum drilling duration per pile (hours)	32.5	40
Maximum volume of drill arisings per pile (m^3)	737	1571
Maximum volume of drill arisings for the Proposed Development (m^3)	197,563	251,327
Maximum number of concurrent drilling events	2	
Minimum distance between concurrent drilling events (km)	1	
Maximum distance between concurrent drilling events (km)	20	

Step 3 – OSP Topside and Fixed Foundation Installation and Commissioning

3.6.20 The OSP jackets will be fixed to the seabed using piles. Piles will be transported to the Array Area by vessel from the fabrication site or port facility, and installed in the seabed at the installation locations (exact locations to be confirmed at final design stage (post-consent)), using methods described previously in Paragraphs 3.6.11 to 3.6.19.

3.6.21 Piling will commence with a lower hammer energy of 675 kJ and will slowly ramp up energy up to a maximum 4,500 kJ over a period of 30 minutes. Concurrent piling may occur between an OSP and a Wind Turbine location. However, there will only be a maximum two concurrent piling events.

3.6.22 The OSP jackets will be delivered to site by barge or delivery vessel and lowered to the seabed using a crane. This could occur before installing the piles (post-piled jacket) or after (pre-piled jacket) Once in place the jackets would be grouted onto the piles.

3.6.23 The PDE for the driven piles associated with the OSP foundations is presented in Table 3.23. Drilling characteristics are presented in Table 3.24.

Table 3.23: PDE for OSPs – Piling Characteristics

Parameter	Maximum Design
Maximum number of piles requiring piling	36
Maximum hammer energy (kJ)	4,500
Soft start energy (% of maximum hammer energy)	15
Maximum soft start duration (minutes)	20
Maximum duration of piling per pile (hours)	13.3
Maximum number of piles installed over 24 hours	4
Maximum duration of piling per day over construction phase (hours)	22
Maximum total number of days when piling may occur over construction phase	36
Maximum number of concurrent piling events	2
Minimum distance between concurrent piling events (km)	1
Maximum distance between concurrent piling events (km)	15

Table 3.24: PDE for OSPs – Drilling Characteristics

Parameter	Maximum Design
Maximum number of piles requiring drilling per foundation	36
Minimum drilling rate (m/hour)	1
Maximum drilling rate (m/hour)	2
Maximum drilling depth (m)	35
Maximum drilling duration (per pile) (hours)	35
Maximum drilling duration (days)	53
Maximum volume of drill arisings per pile (m^3)	1,113
Maximum volume of drill arisings (m^3)	40,079
Maximum number of concurrent drilling events	2

3.6.24 Once the jacket foundations are installed, the OSP topside(s) will be transported to the Array Area via vessel either from the fabrication yard or the port facility. It is likely this will be transported by the installation vessel or on a barge towed by a tug. Once on site, the OSP topside will be rigged up, sea fastening cut, lifted and installed onto the foundation. The topside and foundation will then be welded or bolted together. Rigging, welding and bolting equipment will be available on board the installation vessel.

3.6.25 It is expected that commissioning works will be carried out using a dynamically positioned vessel. Assisting support and supply vessels will be used as required and Crew Transfer Vessels (CTVs) will be used for transfer of personnel to and from the installation vessel.

Step 4 – Interconnector Cable and IAC Installation, Including Cable Burial and/or Protection

3.6.26 A cable lay vessel will be used for installation (lay) of the IACs and Interconnector Cables using various equipment such as a carousel or reels, tensioners and cable lay spread. IACs and Interconnector Cables are typically surface laid prior to cable burial or installation of external cable protection post lay. Cable lay and cable burial can also be performed simultaneously.

3.6.27 There are several options which may be used to bury cables to the minimum target burial depth. Equipment that may be used to bury the static portion of the IAC and Interconnector Cables include:

- Jet trenchers or mass flow excavators which inject water at high pressure into the sediment surrounding the cable. Jet trenching tools use water jets to fluidise the seabed which allows the cable to sink into the seabed under its own weight.
- Mechanical trenchers, usually mounted on tracked vehicles, which use chain cutters or wheeled arms with teeth or chisels to cut a trench across the seabed.
- Cable ploughs are usually towed either from a vessel or vehicle on the seabed. There are two types of plough:
    - a displacement plough which creates a V shaped trench into which the cable can be laid; or
    - a non-displacement plough which simultaneously lift a share of seabed whilst depressing the cable into the bottom of the trench. As the plough progresses, the share of the seabed is replaced on top of the cable.

3.6.28 Paragraph 3.3.50 describes cable crossings potentially required for the IACs and Interconnector Cables.

3.6.29 Cable protection will be used where the target burial depths are not achieved during cable installation and at cable crossings. Cable protection systems are also to be used as static IACs and Interconnector Cables approach and enter the Wind Turbines and OSPs.

3.6.30 Paragraphs 3.3.43 to 3.3.49 provide details on the external cable protection that may be required for IACs and Interconnector Cables.

3.6.31 Paragraph 3.4.16 describes cable crossings potentially required for the Offshore Export Cables.

Step 5 – Offshore Export Cable Installation, Including Cable Burial and/or Protection

3.6.32 Offshore Export Cable installation methods will follow the same methods as described for IACs and Interconnector Cables (see Paragraphs 3.6.26 and 3.6.31).

3.6.33 Paragraphs 3.4.14 to 3.4.15 provide details on the external cable protection that may be required for Offshore Export Cables.

3.6.34 Paragraph 3.4.16 describes cable crossings potentially required for the Offshore Export Cables.

Step 6 – Wind Turbine Transport, Installation and Commissioning

3.6.35 Wind Turbines (comprising nacelle, rotor blades, hub and towers) will be transported to the Array Area by vessel from the pre-assembly port where sub-assemblies (nacelle, rotor blades, and towers), assembly parts, tools and equipment will be loaded onto an installation or support vessel.

3.6.36 At the installation location, the Wind Turbines towers will be lifted onto the pre-installed foundation by the crane on the installation vessel. The nacelle and rotor blades will then be lifted into position. The exact methodology for the assembly will be dependent on the installation contractor and Wind Turbine type.

3.6.37 Static IACs are 'pulled-in' to the Wind Turbines using a cable laying vessel and connected to the Wind Turbine via J-tubes. Following connection to the necessary cabling, a process of testing and commissioning will be undertaken.

Installation Vessels and Helicopters

3.6.38 A number of installation vessels will be used during the construction phase including main installation vessels (e.g. dynamically positioned vessels with heavy lifting equipment), support vessels (including Service Operation Vessels (SOVs)), tugs and anchor handlers, cable installation vessels, guard vessels, survey vessels, CTVs and scour/cable protection installation vessels. Helicopters may also be used for crew transfers.

3.6.39 Table 3.25 presents the PDE for vessels and helicopters used for the construction phase. The number of vessels/helicopters on site at any one time and the total vessel/helicopter movements (return trips) during the entire construction phase are presented in this table. The vessel numbers presented in Table 3.25 are an estimated maximum for the PDE for the purposes of the EIA, and it is anticipated that the actual vessel and helicopter numbers will be less than those presented. The maximum number of vessels (including helicopters) in the Array Area and Export Cable Corridor at any one time is 25 and 16, respectively, and with up to a total of 2,387 return trips.

Table 3.25: PDE for Offshore Infrastructure Installation – Vessels and Helicopters

Parameter	Maximum Design			
	Total Vessels on Site at any one Time		Total Movements (Return Trips Across Installation Activities)	
	Array Area	Export Cable Corridor	Array Area	Export Cable Corridor
Main installation vessels (jack-up/dynamically positioned vessel)	2	N/A	97	N/A
Cargo barge/Heavy Transport Vessels (HTVs) (self-propelled)	2	N/A	97	N/A
Support vessels (including SOVs)	6	1	92	20
Scour protection installation vessels (rock placement)	2	N/A	89	N/A
Grouting vessels	2	N/A	69	N/A
Rock placement vessels	N/A	1	N/A	30
Tug/anchor handlers	2	N/A	97	N/A
Cable installation vessels (laying)	1	1	23	18
Cable installation vessels (burial)	1	1	11	21
Guard vessels	6	4	164	128
Survey vessels	2	1	52	44
CTVs	6	1	770	69
Sandwave clearance vessels	1	1	55	30
Pre-Lay Grapnel Run (PLGR) vessels	1	1	10	17
Boulder/UXO clearance vessels	3	2	45	60
HDD support vessels (spud leg, anchored barge or jack-up vessel)	N/A	1	N/A	6
Dive Support Vessels (DSVs)	N/A	1	N/A	6
Helicopters	1	1	130	137
Total	38	17	1,801	586
Total (excluding helicopters)	37	16	1,671	449
Total on-site at any one time	25	16	N/A	N/A

3.6.40 Jack-up vessels or barges touch down on the seabed when their jack-up spud cans (base structure of each leg) are lowered into place. Jack-up vessel parameters are presented in Table 3.26.

Table 3.26: PDE for Jack-up Vessels

Parameter	Maximum Design
Maximum number of legs per vessel	4
Maximum individual leg diameter (m)	11
Maximum area of spud cans (m^2)	350
Maximum seabed footprint (m^2)	1,400
Maximum number of jack-up positions per OSP and foundation	2

Construction Ports

3.6.41 Fabrication of components for the Offshore Infrastructure is likely to occur at a number of manufacturing sites including those located within Scotland, the United Kingdom (UK), Europe, the Middle East and the Far East. It is likely that components will be transported to final assembly yards on the east coast of Scotland for final fabrication or integration before being towed to the Proposed Development.

3.6.42 It is anticipated that all components will be transported to the Proposed Development for installation via sea transport using vessels and associated equipment. It is not anticipated that large components (e.g. Wind Turbine blades) will be transported via road.

3.6.43 At time of writing this Offshore EIA Report, the Applicant is yet to determine which construction port(s) will be used for the storage, fabrication, pre-assembly and delivery of the Offshore Infrastructure. The Applicant will determine suitable ports based on the facilities available to handle and process components for the Proposed Development. Port selection will take into account logistics to reduce towing and transport distance of foundations and Wind Turbines as far as practicable. The Applicant anticipates that established port licences and operational controls will cover all activities associated with the Proposed Development which are carried out within port. In order to assess an MDS, the assessments within this Offshore EIA Report consider a maximum number of vessels and vessel movements to/from site, where relevant from the east coast of Scotland or England.

3.6.44 Construction personnel will transit to the Proposed Development on the installation vessels or other vessels listed in Table 3.25. CTVs, Service Operation Vessels (SOVs), or helicopters operating from a licenced airfield may be used to transfer crew between the port facility and the Proposed Development during construction, O&M and decommissioning.

Construction Programme

3.6.45 The indicative construction programme for the Proposed Development is provided below for the jacket foundation option, which is assumed to represent the longest construction duration because the piling programme for jacket foundations is longer than for monopiles, this programme therefore represents a conservative maximum duration within the PDE. This indicative construction programme, including the estimated commencement and completion dates, and estimated durations of activities, has been used within the technical chapter assessments of construction impacts.

3.6.46 The Proposed Development will be built out over a period of up to five years including site preparation works (Figure 3.12). During the five-year construction programme separate campaigns (e.g. OSP installation, and Wind Turbine installation) will be undertaken for the relevant Offshore Infrastructure and are likely to occur concurrently across the construction period. It should be noted that construction activities will not occur continuously throughout the five-year construction period, rather, the programme indicates the period within which these activities could occur. Increased construction activity is anticipated within the spring to autumn months, with it likely that limited works would be undertaken during the winter period, as works will be weather dependant.

3.6.47 Site preparation activities will commence in Q2 2031, and Wind Turbine commissioning will be completed in Q1 2036. To account for part years, the Cumulative Effects Assessment (CEA) period is considered over six years.

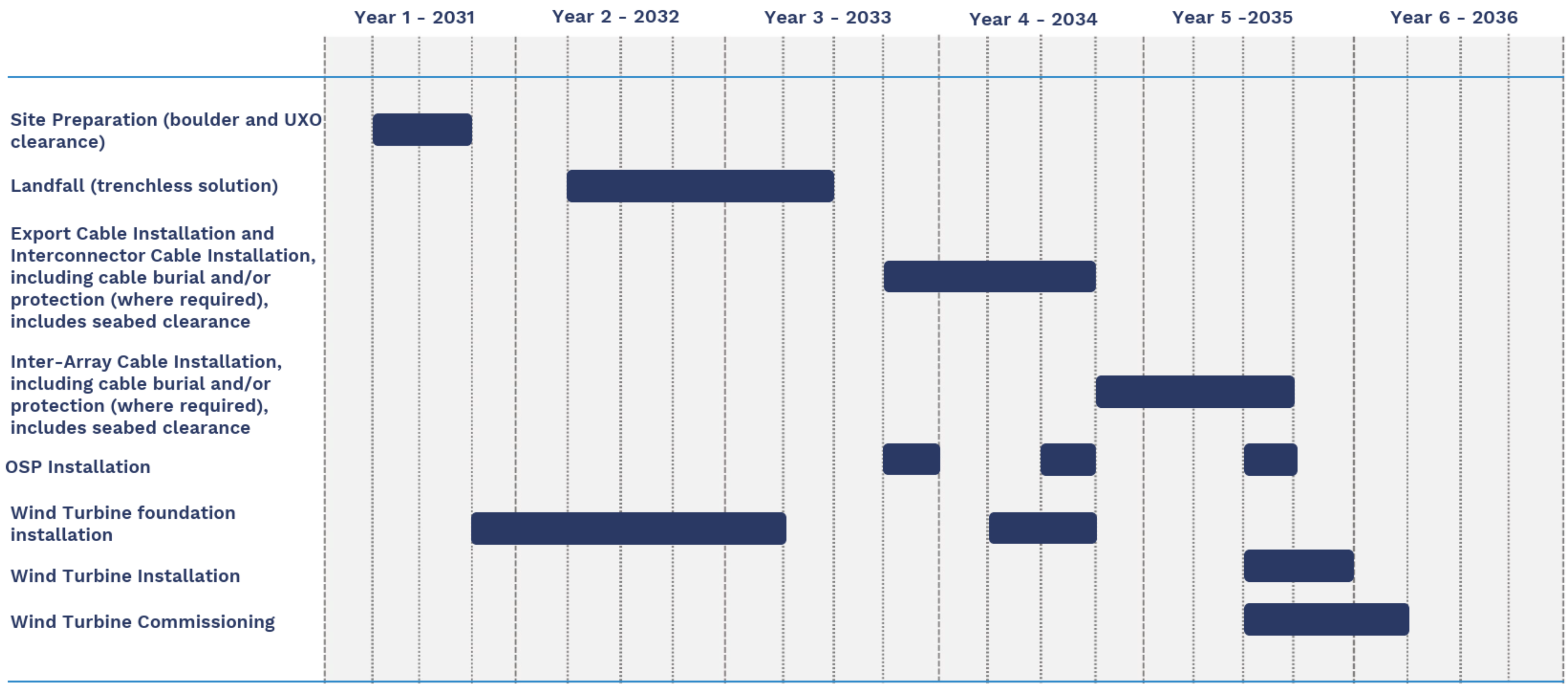


Figure 3.12: Indicative Construction Programme

3.7 Operation and Maintenance Phase

Methodology

3.7.1 The Proposed Development operational lifetime is up to 30 years. The overall O&M strategy will be finalised once the O&M base location and technical specification of the Proposed Development are known, including Wind Turbine type, electrical export option and final project layout. Therefore, this section provides an overview of the potential scheduled and unscheduled O&M activities within the Proposed Development which are reasonably foreseeable.

3.7.2 O&M activities will be conducted using SOVs, CTVs, and/or ROVs. Divers and DSVs may be utilised if required, although it is anticipated that diverless operations will be utilised as far as practicable. Jack-up and/or heavy lift vessels will be used for infrequent major maintenance campaigns associated with the OSPs. ROVs will be used to inspect foundations and cabling. A summary of the reasonably foreseeable O&M activities is provided in the following sections.

3.7.3 Offshore O&M will comprise both preventative and corrective activities.

Foundations and Wind Turbines

3.7.4 The following O&M activities are expected to occur in relation to the Wind Turbines, OSP foundations (including jacket and monopile types), and associated structures:

- routine inspections;
- geophysical surveys;
- repairs or replacements of navigational equipment and other ancillary equipment including condition monitoring equipment;
- removal of marine growth;
- repairs or replacements of corrosion protection anodes;
- blade coating and repairs;
- removal of fishing debris;
- minor repairs and replacements within Wind Turbines;
- major component replacement of Wind Turbines;
- painting or application of other protective coatings;
- replacement of access ladders and boat landings;
- statutory inspections;
- modifications to/replacement of J-tubes and other ancillary structures; and
- replacement of scour protection.

3.7.5 It is assumed that the majority of these activities will be carried out using uncrewed surface vessels (USVs), SOVs, CTVs, ROVs, heavy lift vessels, cable repair vessels, jack-up vessels, and tug vessels, with appropriate equipment for the activity to be undertaken. Divers and DSV may be required if necessary. Although it is assumed that the majority of these O&M activities will be routinely scheduled throughout the lifetime of the Proposed Development, whilst repairs and replacements of navigational equipment, corrosion protection anodes and access ladders and boat landings, removal of marine growth and fishing debris, and painting are expected to be unscheduled. The frequency of these unscheduled activities will be dependent on the findings of routine inspections and will be carried out during other works as and when required.

OSP Topsides

3.7.6 The following O&M activities are expected to occur in relation to the OSP topsides:

- routine inspections;
- removal of marine growth;
- replacement of consumables and minor components;
- major component replacement; and
- painting or other coatings.

3.7.7 It is assumed that the majority of these activities will be carried out using SOVs and CTVs. Jack-up barges and/or heavy lift vessels may be required in the case of major component replacement. Although it is anticipated that the majority of these O&M activities will be routinely scheduled throughout the lifetime of the Proposed Development, replacement of consumables and minor components is an unscheduled activity which will occur as required, dependent upon the findings of routine inspections.

IACs and Interconnector Cables

3.7.8 The following O&M activities are expected to occur in relation to both the IACs and Interconnector Cables:

- routine inspections;
- geophysical surveys;
- IAC/Interconnector Cable repair;
- IAC ancillary equipment repair;
- IACs and Interconnector Cables reburial, de-burial (if cables have been further buried due to seabed mobility) and, reinstatement (remedial work) of cable protection (if required);
- removal of marine growth and/or fishing debris;
- modifications to/replacement of J-tubes; and
- replacement of scour protection.

3.7.9 In relation to IAC cable repairs and seabed interventions, it is anticipated that up to one cable repair per year may be required for static cables. These repairs may involve the excavation and reburial of up to 4,915 m of cable annually, depending on the extent of damage and seabed conditions. In addition, remedial cable protection may be applied over a similar maximum annual length of 4,915 m.

3.7.10 For interconnector Cable repairs and seabed interventions, it is anticipated that up to 0.18 cable repairs per year may be required. These activities may involve the excavation and reburial of up to 2,040 mof cable annually, depending on the nature and location of the fault. Similarly, remedial cable protection may be applied over a maximum annual length of 2,040 m.

3.7.11 It is assumed that the majority of these activities will be carried out using USVs, SOVs, CTVs, ROVs, cable repair vessels, and survey vessels, with appropriate equipment for the activity to be undertaken (including burial equipment). Divers and DSV may be required if necessary. It is anticipated that the majority of these O&M activities will be routinely scheduled throughout the lifetime of the Proposed Development.

Export Cables

3.7.12 Export Cable repair and seabed intervention works are expected to involve up to one cable repair per year for static cables. These works may require the excavation and reburial of up to 6,390 m of cable annually. Remedial cable protection may be applied over a similar maximum annual length of 6,390 m.

Operation and Maintenance Vessels

3.7.13 Table 3.27 and Table 3.28 presents the PDE for vessels involved in O&M activities for the Proposed Development.

Table 3.27: PDE for Vessels with Annual Trips Required During the O&M Phase

Parameter	Maximum Design			
	Maximum Total Number of Vessels on Site at any One Time		Maximum Total Movements (Return Trips Annually Across O&M Phase)	
	Array Area	Export Cable Corridor	Array Area	Export Cable Corridor
SOV/workboats	3	1	43	20
CTVs	3	2	500	20
Cable repair vessels (laying)	1	1	2	20
Cable repair vessels (burial solution)	1	1	2	31
DSV	1	1	7	6
Other vessels (including heavy lift vessels)	1	N/A	6	N/A
Guard vessels	2	2	28	28
Helicopters	2	1	20	10

Parameter	Maximum Design			
	Maximum Total Number of Vessels on Site at any One Time		Maximum Total Movements (Return Trips Annually Across O&M Phase)	
	Array Area	Export Cable Corridor	Array Area	Export Cable Corridor
Total	14	9	608	135
Total (excluding helicopters)	12	8	588	125

Table 3.28: PDE for Vessels Without Annual Trips Required During the O&M Phase

Parameter	Maximum Design			
	Maximum Total Number of Vessels on Site at any One Time		Maximum Total Movements (Return Trips in Total Across O&M Phase)	
	Array Area	Export Cable Corridor	Array Area	Export Cable Corridor
Rock dumping vessels	1	1	70	41
Sandwave clearance vessels	1	1	12	12
Survey vessels	1	1	35	26
PLGR vessels	1	1	12	12
Boulder clearance vessels	1	1	12	12
UXO clearance vessels	1	1	5	5
Micro-tunnelling or HDD support vessels	N/A	1	N/A	6
Total	6	7	146	114

3.8 Decommissioning Phase

3.8.1 In line with the requirements under Section 105 of the Energy Act 2004 (as amended) (further detailed in Volume 1, Chapter 2: Policy and Legislation) the Applicant will prepare a Decommissioning Programme for approval by the Scottish Ministers which will include anticipated costs and financial securities, and consider good industry practice, guidance and legislation relating to decommissioning at the time. A draft of the Decommissioning Programme will be submitted to Marine Directorate – Licensing and Operations Team (MD-LOT) prior to construction of the Proposed Development. The Decommissioning Programme will be updated during the Proposed Development's lifetime to take account of changing good practice, new technologies and any changes to legislation.

3.8.2 At the end of the Proposed Development's operational lifetime, it is expected that all structures above the seabed will be fully removed where practicably feasible. Driven and/or drilled piles installed as part of the Wind Turbine foundations, the static IACs, Interconnector Cables, Offshore Export Cables, scour protection and cable protection are either expected to remain *in situ* or the method of decommissioning is yet to be determined. Legislation, guidance and good practice will be kept under review throughout the lifetime of the Proposed Development and will be followed at the time of decommissioning. Environmental conditions and sensitivities will also be considered since removal of structures may result in greater environmental impacts in comparison to leaving *in situ*.

3.8.3 The sequence of decommissioning is likely to be the reverse of the construction sequence, and similar types and numbers of vessels and equipment are expected to be involved. The Option for Lease agreement for the Bowdun OWF Project awarded by the Crown Estate Scotland requires the Proposed Development to be decommissioned at the end of its lifetime.

Wind Turbine Components

3.8.4 The fixed foundations will be removed from site by reversing the methods used to install them.

OSP Topsides

3.8.5 OSP topsides will be fully removed from site by reversing the methods used to install them.

OSP Fixed Jacket Foundations

3.8.6 Piles will be cut at seabed level and left *in situ*, depending on seabed mobility, to reduce further disruption of the seabed. This will be reviewed throughout the lifetime of the Proposed Development and the most up to date and good practice guidance at time of decommissioning will be followed. The MDS has been assessed for each topic within this Offshore EIA Report. Jackets will be fully removed from site.

Scour Protection

3.8.7 It is currently proposed that scour protection will be left *in situ* subject to the final material used. Good practice guidance at time of decommissioning will be followed. The MDS has been assessed for each topic within this Offshore EIA Report.

IACs and Interconnector Cables

3.8.8 The approach for decommissioning the IACs and the Interconnector Cables on the seabed is yet to be determined. However, this will be reviewed throughout the lifetime of the Proposed Development and good practice guidance at time of decommissioning will be followed. Where cables remain buried these may be cut and left *in situ* taking account of environmental sensitivity at the time of decommissioning. The MDS has been assessed for each topic within this Offshore EIA Report.

Offshore Export Cables

3.8.9 The approach for decommissioning the Offshore Export Cables is yet to be determined. To reduce the environmental disturbance during decommissioning, the preferred option at Landfall is to leave the Offshore Export Cables buried in place in the ground with the cable ends cut, sealed and securely buried as a precautionary measure.

Cable Protection

3.8.10 The approach for decommissioning the cable protection systems is yet to be determined. However, this will be reviewed throughout the lifetime of the Proposed Development and good practice guidance at time of decommissioning will be followed. The MDS has been assessed for each topic within this Offshore EIA Report.

3.9 Health and Safety

3.9.1 Risk assessments for all elements of the Proposed Development will be undertaken as per the relevant government guidance and the Applicant's good practice procedures. The risk assessments will form the basis of the methods and safety mitigations put in place across the lifetime of the Proposed Development.

Recommended Safe Passing Distances and Aids to Navigation

Safety Zones, Recommended Safe Passing Distances and Notice to Mariners

3.9.2 The Applicant will communicate with other mariners of safe clearance distances around construction, installation, O&M and decommissioning activities during the construction and operation of the Proposed Development as per standard practice and guidance.

Statutory Safety Zones

3.9.3 Volume 1, Chapter 2: Policy and Legislation describes the legislation for establishment of statutory safety zones. The Applicant intends to apply for the following safety zones for the Proposed Development:

- temporary (or rolling) 500 m safety zones surrounding the location of all surface piercing structures where construction work is being undertaken by a construction vessel;
- 50 m safety zones around all partially completed or completed surface piercing structures which are not yet fully commissioned during the construction phase; and
- 500 m around any structure where major maintenance is ongoing (major maintenance works are defined within the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007.

3.9.4 The Applicant will apply for statutory decommissioning safety zones during the decommissioning phase (as appropriate) which are not anticipated to exceed the standard 500 m safety zone.

Recommended Safe Passing Distances

3.9.5 The Applicant may use recommended safe passing distances during the construction, O&M and decommissioning phases for the safety of third party vessels. Notice to Mariners (NtMs) and Kingfisher Bulletins will be used to communicate these to sea users during all phases of the Proposed Development.

Aids to Navigation

3.9.6 The Wind Turbines and OSPs will be lit and marked to aid navigation. The LMP (Volume 4, Appendix 31: Outline Lighting and Marking Plan) and Aids to Navigation Outline Management Plan (Volume 4, Appendix 32: Outline Aid to Navigation Management Plan) for the Proposed Development will be defined post consent in consultation with the Northern Lighthouse Board (NLB), Maritime and Coastguard Agency (MCA), the Civil Aviation Authority (CAA) and the Ministry of Defence (MOD).

3.9.7 Marine aids to navigation will be provided throughout the lifetime of the Proposed Development in accordance with the requirements of the NLB, MCA and MOD, and in adherence to Civil Aviation Publication (CAP) 393 Article 223 (CAA, 2016 (as amended)), unless otherwise agreed Monitoring and maintenance of all navigational aids associated with the Array Area will be undertaken so that the relevant CAA availability targets are met.

3.10 Repowering

3.10.1 Although it is standard procedure for sectors where a non-renewable resource is being exploited, such as oil and gas, for removal of all structures on the seabed as part of offshore decommissioning, the alternative option of repowering may be considered for offshore renewables – especially as, at the time of decommissioning, the need for the power generated will likely still exist.

3.10.2 The operational life of the Proposed Development is expected to be up to 30 years, during which there will be a requirement for upkeep and maintenance of the Proposed Development, as described in Section 3.7.

3.10.3 'Repowering' of the Proposed Development at or near the end of its design life may be considered suitable, for example, where new technology becomes available. In this example, Wind Turbines and/or foundations may be reconstructed and replaced with those of a different specification or design. If the specifications and designs of the new Wind Turbines and/or foundations fell outside of the PDE, if the impacts associated with the construction, O&M, and/or decommissioning of the replacement Wind Turbines and/or foundations were to fall outside those considered by this Offshore EIA Report, or if repowering would extend the operational lifetime beyond the maximum operational period defined in the PDE (30 years), further consent(s) (and potentially an EIA Report) would be required for repowering. Therefore, this is outside of the scope of this Offshore EIA Report.

3.11 Embedded Mitigation

3.11.1 A number of Embedded Mitigation measures have been considered as part of the PDE which the Applicant commits to deliver as part of the Proposed Development. Volume 3, Technical Appendix 4.6: Schedule of Mitigation and Commitments presents the Embedded Mitigation measures for the Proposed Development. Relevant mitigation plans are included within these commitments and form part of the PDE as Embedded Mitigation. As these measures and plans have been incorporated into the project design of the Proposed Development, and forms part of the PDE (as described in this chapter), they have also been considered within the topic specific assessments within Volume 2, Chapters 7 to 23. Further details of the Embedded Mitigation measures, Additional Mitigation and monitoring commitments are provided in Volume 3, Technical Appendix 4.6: Schedule of Mitigation and Commitments.

3.12 Residues, Emissions and Waste

3.12.1 A description of the anticipated residues, emissions and wastes arising from the Proposed Development, and a description of the likely significant environmental effect resulting from the emission of pollutants, noise, vibration, light, heat and radiation, the creation of nuisances, and the disposal and recovery of waste, are required as per the EIA Regulations. These requirements, and where these are addressed in this Offshore EIA Report, are presented in Table 3.29.

Table 3.29: Residues and Emissions

EIA Regulations Requirement	Where Considered Within the Offshore EIA Report
Description of expected residues and emissions and the production of waste, where relevant, and a description of the likely significant environmental effect of the Proposed Development on the environment resulting from the emission of pollutants, noise, vibration, light, heat and radiation, the creation of nuisances, and the disposal and recovery of waste.	The following chapters assess the likely significant environmental effects associated with the emission of noise and vibration and associated nuisances: • Volume 2, Chapter 8: Benthic Ecology; • Volume 2, Chapter 9: Fish and Shellfish Ecology; • Volume 2, Chapter 10: Marine Mammals; • Volume 2, Chapter 20: Inter-related Effects; and • Volume 3, Technical Appendix 10.4: Subsea Noise Technical Report. The following chapters assess likely significant environmental effects associated with electromagnetic fields: • Volume 2, Chapter 8: Benthic Ecology; • Volume 2, Chapter 9: Fish and Shellfish Ecology; and • Volume 2, Chapter 10: Marine Mammals. Disposal and recovery of waste is addressed in: • Volume 4, Appendix 24: Outline Environmental Management Plan.

Waste Management

3.12.2 The construction and decommissioning phases of the Proposed Development in particular will generate waste. The Waste Management Plan (WMP) will form part of the Environmental Management Plan and will describe the procedures for handling waste materials, the quantities of waste types generated as a result of the Proposed Development activities, and how these will be managed (e.g. disposal, reuse, recycle or recovery). Information on the management arrangements for the identified waste types and management facilities in the vicinity of the Proposed Development will also be provided within the WMP.

3.12.3 The WMP will be provided prior to construction when further detailed design information is available. An Outline Environmental Management Plan (including a WMP) is provided as part of the application (Volume 4, Appendix 24: Outline Environmental Management Plan).

3.13 Natural Resources

3.13.1 A description of the use of natural resources is also required to be provided as per the EIA Regulations. Where this is addressed in this Offshore EIA Report is presented in Table 3.30.

Table 3.30: Natural Resources

EIA Regulations Requirement	Where Considered Within the Offshore EIA Report
A description of the likely significant environmental effects of the Proposed Development on the environment resulting from the use of natural resources, in particular land, soil, water and biodiversity, considering as far as possible the sustainable availability of these resources.	The following chapters assess seabed disturbance (land and soil): • Volume 2, Chapter 7: Physical Processes; • Volume 2, Chapter 8: Benthic Ecology; and • Volume 2, Chapter 9: Fish and Shellfish Ecology. The following chapter assess the use of rocks: • Volume 2, Chapter 8: Benthic Ecology; • Volume 2, Chapter 13: Commercial Fisheries; and • Volume 2, Chapter 14: Shipping and Navigation.

3.14 Risk of Major Accidents and Disasters

3.14.1 Volume 2, Chapter 17: Major Accidents and Disasters assesses the risk of major accidents and disasters which may arise from the Proposed Development.

References

Bowdun Offshore Wind Farm Limited (2024). *Bowdun Offshore Wind Farm Offshore Scoping Report*. Available at: https://marine.gov.scot/sites/default/files/240822_-_bowdun_offshore_wind_farm_-_scop-0056_-_scoping_report_submission_240822_-_developer_to_md-lot.pdf. Accessed on: 08 July 2025.

Bowdun Offshore Wind Farm Limited (2025). Bowdun Onshore EIA Report. Available at: https://thistlewindpartners.scot/bowdun/bowdun-document-library/. Accessed on: 18 December 2025.

Scottish Government (2020). Sectoral Marine Plan for Offshore Wind Energy, 78pp.

Scottish Government (2022). – Rochdale envelope. Available at: https://www.gov.scot/publications/guidance-applicants-using-design-envelope-applications-under-section-36-electricity-act-1989/. Accessed on: 08 July 2025.

Annex A: Coordinates of Proposed Development

Table A1.1: Array Area Coordinates

Array Coordinate No.	X (m) (WGS84 UTMz 30N)	Y (m) (WGS84 UTMz 30N)	Array Coordinate No.	X (m) (WGS84 UTMz 30N)	Y (m) (WGS84 UTMz 30N)
1	610888.8173	6318109.4130	35	592706.6216	6316132.5440
2	610571.5078	6317733.9740	36	592991.9108	6316795.3430
3	610254.1983	6317358.5350	37	593400.3196	6317744.1800
4	609619.5789	6316607.6590	38	593808.7284	6318693.0170
5	608984.9590	6315856.7860	39	594879.9411	6318859.0270
6	608350.3387	6315105.9150	40	595951.1537	6319025.0380
7	607715.7180	6314355.0470	41	597022.3663	6319191.0480
8	607081.0969	6313604.1810	42	598093.5790	6319357.0590
9	606446.4753	6312853.3180	43	599166.1523	6319523.2800
10	605811.8533	6312102.4580	44	598197.5442	6320040.3900
11	605177.2309	6311351.5990	45	597228.9361	6320557.4990
12	604542.6081	6310600.7440	46	596260.3280	6321074.6090
13	603907.9849	6309849.8900	47	595288.2742	6321593.5580
14	603273.3612	6309099.0400	48	595763.7018	6322525.2690
15	602638.7372	6308348.1910	49	596239.1294	6323456.9790
16	602004.1127	6307597.3450	50	596714.5570	6324388.6900
17	601030.0371	6307757.6530	51	597191.1068	6325322.6000
18	600055.9638	6307917.9610	52	597413.3242	6325205.6090
19	599081.8928	6308078.2670	53	598255.5329	6324762.1100
20	598107.8240	6308238.5730	54	599097.7428	6324318.6110
21	597133.7575	6308398.8780	55	599939.9540	6323875.1090
22	596159.6931	6308559.1820	56	600782.1664	6323431.6050
23	595185.6310	6308719.4860	57	601624.3801	6322988.1000
24	594211.5709	6308879.7890	58	602466.5950	6322544.5920
25	593621.6340	6308976.8470	59	603308.8113	6322101.0830
26	593890.3927	6309925.5410	60	604151.0288	6321657.5720
27	594159.1436	6310874.2080	61	604993.2477	6321214.0590
28	594427.8945	6311822.8750	62	605835.4679	6320770.5440
29	594697.6738	6312775.1720	63	606677.6894	6320327.0270
30	593712.5111	6313168.8380	64	607519.9122	6319883.5080
31	592727.2598	6313562.5400	65	608362.1365	6319439.9870
32	591741.6847	6313956.3710	66	609204.3620	6318996.4650
33	592160.4098	6314900.7000	67	610046.5890	6318552.9400
34	592579.1349	6315845.0300	68	610888.8173	6318109.4130

Table A1.2: Export Cable Corridor Coordinates

Array Coordinate No.	X (m) (WGS84 UTMz 30N)	Y (m) (WGS84 UTMz 30N)	Array Coordinate No.	X (m) (WGS84 UTMz 30N)	Y (m) (WGS84 UTMz 30N)
1	542425.1153	6296567.745	37	542575.6444	6296870.031
2	542439.4996	6296582.099	38	542576.3019	6296872.941
3	542455.9437	6296599.71	39	542578.0015	6296886.667
4	542460.2303	6296604.763	40	542579.2418	6296911.287
5	542475.4832	6296623.817	41	542579.3401	6296904.56
6	542477.4263	6296626.356	42	542579.3646	6296902.888
7	542481.0241	6296631.999	43	542579.4024	6296913.989
8	542485.6762	6296640.098	44	542580.4736	6296922.806
9	542488.5777	6296645.491	45	542581.9522	6296931.128
10	542493.5514	6296656.214	46	542583.7306	6296939.455
11	542498.7839	6296669.762	47	542588.1912	6296953.131
12	542505.9873	6296689.418	48	542592.2996	6296964.212
13	542511.1812	6296701.505	49	542593.5471	6296967.13
14	542514.6652	6296710.147	50	542603.9539	6296989.314
15	542517.629	6296718.801	51	542606.6615	6296994.964
16	542521.0132	6296727.431	52	542609.3651	6297000.214
17	542525.7551	6296741.702	53	542611.111	6297003.24
18	542530.0288	6296752.425	54	542614.4677	6297011.7
19	542536.739	6296766.824	55	542620.0382	6297024.702
20	542538.7521	6296770.938	56	542625.3435	6297036.001
21	542539.641	6296772.867	57	542629.4916	6297044.372
22	542543.0249	6296781.517	58	542634.1507	6297052.671
23	542544.3239	6296784.326	59	542636.8486	6297058.31
24	542545.9161	6296788.29	60	542641.3064	6297066.696
25	542549.3433	6296796.031	61	542644.604	6297072.355
26	542549.8085	6296797.047	62	542649.5839	6297079.238
27	542550.9587	6296800.464	63	542656.1315	6297087.654
28	542551.6206	6296803.074	64	542668.0139	6297100.569
29	542555.393	6296811.83	65	542676.0774	6297107.907
30	542560.0995	6296825.1	66	542684.4419	6297115.86
31	542562.713	6296831.039	67	542690.3374	6297122.366
32	542563.572	6296833.851	68	542692.8847	6297125.303
33	542564.9294	6296836.772	69	542695.7433	6297128.155
34	542568.1077	6296845.119	70	542698.3904	6297131.104
35	542570.0256	6296850.747	71	542700.6391	6297133.947
36	542571.5451	6296856.27	72	542708.6687	6297145.655

Array Coordinate No.	X (m) (WGS84 UTMz 30N)	Y (m) (WGS84 UTMz 30N)	Array Coordinate No.	X (m) (WGS84 UTMz 30N)	Y (m) (WGS84 UTMz 30N)
73	542718.2619	6297159.186	**110**	542905.7624	6297371.079
74	542720.6305	6297162.031	**111**	542911.0931	6297375.858
75	542724.7579	6297167.712	**112**	542913.7012	6297378.736
76	542738.2555	6297184.38	**113**	542915.8208	6297381.517
77	542743.3971	6297189.776	**114**	542916.8041	6297382.969
78	542750.9901	6297198.517	**115**	543114.1011	6295323.017
79	542759.4722	6297208.692	**116**	543115.8926	6295321.688
80	542762.1293	6297211.641	**117**	543115.8977	6295321.684
81	542764.398	6297214.484	**118**	543118.1367	6295320.023
82	542768.35	6297219.162	**119**	543148.228	6297286.617
83	542774.0591	6297226.786	**120**	543161.3274	6297285.46
84	542778.1764	6297232.467	**121**	543205.4303	6294706.332
85	542780.9377	6297235.817	**122**	543214.133	6297264.403
86	542797.2934	6297256.748	**123**	543227.2758	6297259.162
87	542805.2962	6297265.495	**124**	543280.2288	6297238.046
88	542810.1148	6297271.096	**125**	543280.2288	6297238.046
89	542817.1289	6296281.328	**126**	543312.5901	6294686.23
90	542823.4331	6297286.351	**127**	543396.6976	6297191.602
91	542824.9985	6296270.628	**128**	543486.7356	6294678.626
92	542824.9985	6296270.628	**129**	543595.2403	6294689.313
93	542825.7032	6297289.095	**130**	543722.9452	6294717.625
94	542829.464	6297293.17	**131**	543797.0687	6294742.411
95	542831.9312	6297296.116	**132**	544103.2943	6296996.738
96	542840.327	6297304.669	**133**	544106.6752	6294859.582
97	542845.7728	6297309.779	**134**	544368.9412	6294961.397
98	542854.8755	6297318.543	**135**	544876.5776	6297289.388
99	542857.957	6297321.198	**136**	544886.619	6295155.247
100	542860.714	6297324.158	**137**	545474.9501	6295377.896
101	542871.603	6297334.558	**138**	545932.0963	6297688.852
102	542879.2381	6297341.1	**139**	553559.5161	6298437.433
103	542885.2813	6297345.708	**140**	564119.2471	6304571.817
104	542890.7331	6297350.408	**141**	591741.6855	6313956.37
105	542893.6032	6297353.161	**142**	592311.3887	6315241.193
106	542896.2732	6297355.91	**143**	593115.9178	6313407.234
107	542898.8373	6297359.067			
108	542900.5946	6297362.003			
109	542904.0123	6297367.654			