NORTH FALLS

Offshore Wind Farm

PRELIMINARY ENVIRONMENTAL INFORMATION REPORT

Chapter 5 Project Description

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Project	North Falls Offshore Wind Farm
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Glossary of Acronyms

AIL	Abnormal Indivisible Load
AIS	Air Insulated Switchgear
bgl	Below Ground Level
CBS	Cement Bound Sand
CL:AIRE	Contaminated Land: Applications in Real Environments
DCO	Development Consent Order
DNO	Distribution Network Operation
DTS	Distributed Temperature Sensing
EIA	Environmental Impact Assessment
ES	Environmental Statement
GBS	Gravity Base System
GGOW	Greater Gabbard Offshore Wind Farm
GIS	Gas Insulated Switchgear
HDPE	High-density polyethylene
HGV	Heavy Goods Vehicle
HV	High Voltage
HVAC	High Voltage Alternating Current
LAT	Lowest Astronomical Tide
MCZ	Marine Conservation Zone
MHWS	Mean High Water Springs
MLWS	Mean Low Water Springs
MV	Medium Voltage
NFOW	North Falls Offshore Wind Farm Limited
NPPF	National Planning Policy Framework
NPS	National Policy Statement
OSP	Offshore Substation Platforms
OWF	Offshore Wind Farm
PEIR	Preliminary Environmental Information Report
PRoW	Public Rights of Way
ROV	Remotely Operated Vehicle
RPM	Rotations Per Minute
SAC	Special Area Of Conservation
SCADA	Supervisory Control and Data Acquisition
SPA	Special Protection Area
SVC	Static VAR Compensator
WTG	Wind Turbine Generators

Glossary of Terminology

Array cables	Cables which link the wind turbine generators with each other and the offshore substation platform(s).
Cable circuit	A bundle which could comprise three power cables; three telecommunications cables; and one earth cable
Cable construction compound	Area set aside to facilitate construction of the onshore cable route. Will be located adjacent to the onshore cable route, with access to the highway.
Haul road	The track along the onshore cable route used by construction traffic to access different sections of the onshore cable route.
Horizontal directional drill	Trenchless technique to bring the offshore cables ashore at the landfall. The technique will also be used for installation of the onshore export cables at sensitive areas of the onshore cable route.
Interconnector cable	Cable between the northern and southern array areas
Interconnector cable corridor	The corridor of the seabed between the northern and southern array areas within which the Interconnector cable will be located.
Jointing bay	Underground structures constructed at regular intervals along the onshore cable route to join sections of cable and facilitate installation of the cables into the buried ducts.
Landfall	The location where the offshore cables come ashore.
Landfall construction compound	Compound at landfall within which HDD or other trenchless technique would take place.
Landfall search area	Locations being considered for the landfall, comprising the Essex coast between Clacton-on-Sea and Frinton-on-Sea.
Link boxes	Underground chambers or above ground cabinets next to the onshore export cables housing low voltage electrical earthing links.
National Grid connection point	The grid connection location for the Project. National Grid are proposing to construct new electrical infrastructure to allow the Project to connect to the grid, and this new infrastructure will be located at the National Grid connection point.
National Grid substation connection works	Infrastructure required to connect the Project to the National Grid's connection point.
Offshore cable corridor	The corridor of seabed from array areas to the landfall within which the offshore export cables will be located.
Offshore export cables	The cables which bring electricity from the offshore substation platform(s) to the landfall.
Offshore project area	The overall area comprising the array areas and the offshore cable corridor.
Offshore substation platform(s)	Fixed structure(s) located within the array areas, containing electrical equipment to aggregate the power from the wind turbine generators and convert it into a more suitable voltage for export to shore via offshore export cables.
Onshore cable corridor(s)	Onshore corridor(s) within which the onshore export cables and associated infrastructure will be located. A final onshore cable route for which consent will be sought will be selected from within these corridor(s).
Onshore cable route	Onshore route within which the onshore export cables and associated infrastructure would be located.
Onshore export cables	The cables which take the electricity from landfall to the onshore substation. These comprise High Voltage Alternative Current (HVAC) cables, buried underground.
Onshore project area	The boundary in which all onshore infrastructure required for the Project will be located (i.e., landfall; onshore cable route, accesses, construction compounds; onshore substation and National Grid substation extension), as considered within the PEIR.

Onshore scoping area	The boundary in which all onshore infrastructure required for the Project will be located, as considered within the North Falls EIA Scoping Report.
Onshore substation	A compound containing electrical equipment required to transform and stabilise electricity generated by the Project so that it can be connected to the National Grid.
Onshore substation construction compound	Area set aside to facilitate construction of the onshore substation. Will be located adjacent to the onshore substation (location not yet defined).
Onshore substation zone	Area within which the onshore substation will be located.
Safety zone	A marine zone outlined for the purposes of safety around a possibly hazardous installation or works / construction area
Scour protection	Protective materials to avoid sediment being eroded away from the base of the wind turbine generator foundations and offshore substation platform foundations as a result of the flow of water.
The Applicant	North Falls Offshore Wind Farm Limited (NFOW).
The Project Or 'North Falls'	North Falls Offshore Wind Farm, including all onshore and offshore infrastructure.
Transition joint bay	Underground structures that house the joints between the offshore export cables and the onshore export cables
Trenchless crossing compound	Areas within the cable corridor which will house trenchless crossing (e.g., HDD) entry or exit points.
Wind turbine generator	Power generating device that is driven by the kinetic energy of the wind

5 Project Description

5.1 Introduction

1. This chapter of the Preliminary Environmental Information Report (PEIR) provides a full description of the physical components of the North Falls Offshore Wind Farm (OWF) project (herein 'North Falls' or 'the Project').
2. As discussed in Chapter 1 Introduction (Volume I), North Falls is an extension to the existing Greater Gabbard Offshore Wind Farm (GGOW), in the outer Thames Estuary. The Project would make an important contribution to UK policies and targets through the generation of clean, low carbon, renewable electricity (see Chapter 2 Need for the Project, Volume I).
3. The chapter describes the necessary construction, operation and maintenance, and the decommissioning of both onshore and offshore components of the Project. The Project has an indicative design life of approximately 30 years.
4. At this stage of the Project's development, some optionality is required in order to future proof the Development Consent Order (DCO). This is a standard approach and is discussed further in Section 5.4.
5. Should refinements to the Project design be required following consultation on the PEIR, these will be reported on and assessed in the Environmental Statement (ES) which will support the DCO application.

5.2 Consultation

6. Consultation regarding North Falls has been undertaken through a number of forums, as discussed in Chapter 7 Technical Consultation (Volume I). Table 5.1 outlines North Falls Offshore Wind Farm Limited (NFOW)s response to key points raised in relation to the Project description.
7. Where appropriate, this chapter will be updated following the consultation on the PEIR in order to produce the final design envelope upon which the DCO application will be based. It is likely that electricity transmission and distribution optionality will be included in the DCO, as a result of the high levels of programme uncertainty surrounding the commercial, regulatory and legislative frameworks required to facilitate options 1 and 2 as described in Section 5.4.1.

Table 5.1 Consultation responses specific to the Project description

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
Essex County Council	August 2021 Scoping Opinion	It is noted that for on shore infrastructure, the development is not fixed at this time and relies on the as quoted "Rochdale Envelope" as set out in Advice Note 9. However, and for the purpose of this Scoping Submission, the area to be covered by this envelope is set at over 150 square kilometres (ref Scoping Report para 43, and figure 1.4, Volume II). It is firstly questioned as to whether this can correctly be considered as falling within this so-called envelope due to its significant size, and secondly makes the effects of the development hugely difficult to predict in anything other than general terms. ECC is told this will focus down to a proposed landfall and connection point early in 2021 however, and dependant on the same, it may be necessary to re- Scope the development and consider its true impacts relevant to specific proposals again. Alternatively it is considered reasonable to say that as the impact of the development are not known it is impossible to scope out any topic at this particular time. This is the view of the Joint Councils at this time.	The onshore scoping area approach has been used successfully on consented offshore wind farms, such as Norfolk Vanguard, East Anglia TWO and East Anglia ONE North, where there is uncertainty from National Grid on the precise connection point at the time of scoping. Consulting on options through the scoping process, enables consultee responses to be considered during the site selection process. The scoping process aims to identify likely significant effects that require further assessment through the EIA and where doubt remains, the effect is scoped in. This PEIR represents the next step in refining the Project envelope and enabling consultation on the likely significant effects of the Project prior to production of the final Environmental Statement (ES).
Health and Safety Executive	August 2021 Scoping Opinion	According to HSE's records the proposed DCO application boundary for this Nationally Significant Infrastructure Project is not within the consultation zones of any major accident hazard sites or major accident hazard pipelines. This is based on the current configuration as illustrated in, for example, 'Onshore Scoping Area Drawing Number PB9244-RHD-ZZ-ON-DR-GS-0060' of the document 'North Falls offshore Windfarm Environmental Impact Assessment Scoping Report Document Reference No:004027770-04 Date: 16/07/21 Revision: 04'. HSE's Land Use Planning advice would be dependent on the location of areas where people may be present. When we are consulted by the Applicant with further information under Section 42 of the Planning Act 2008, we can provide full advice.	Noted.

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
Health and Safety Executive	August 2021 Scoping Opinion	The presence of hazardous substances on, over or under land at or above set threshold quantities (Controlled Quantities) will probably require Hazardous Substances Consent (HSC) under the Planning (Hazardous Substances) Act 1990 as amended. The substances, alone or when aggregated with others for which HSC is required, and the associated Controlled Quantities, are set out in The Planning (Hazardous Substances) Regulations 2015 as amended. HSC would be required to store or use any of the Named Hazardous Substances or Categories of Substances at or above the controlled quantities set out in Schedule 1 of these Regulations. Further information on HSC should be sought from the relevant Hazardous Substances Authority.	Hazardous substances above set threshold quantities are not expected to be part of the Project design, and therefore hazardous substances consent is not anticipated.
Health and Safety Executive	August 2021 Scoping Opinion	Regulation 5(4) of the Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 requires the assessment of significant effects to include, where relevant, the expected significant effects arising from the proposed development's vulnerability to major accidents. HSE's role on NSIPs is summarised in the following Advice Note 11 Annex on the Planning Inspectorate's website - Annex G – The Health and Safety Executive . This document includes consideration of risk assessments on page 3.	An assessment of the risk of major accidents and/or disasters is provided in Section 5.9.
Health and Safety Executive	August 2021 Scoping Opinion	There are no licensed explosive sites showing in the area of the proposed development.	Noted.
Natural England	August 2021 Scoping Opinion	**Section 1.5 Point 26** The scoping report notes that the export cable corridor passes through a number of designated sites. However, it is also important to note that both the northern and southern arrays are situated in the Southern North Sea Special Area of Conservation (SAC) and the southern array is partially located within the Kentish Knock East Marine Conservation Zone (MCZ). The location of the site within these sites should be noted in the ES. It would also be useful to provide a separate overview or section of the	Section 5.6.1 describes the location of the offshore project area, including in relation to designated sites. Each technical chapter describes the relevant study area or zone of influence in relation to the specific receptors. A draft Report to Inform Appropriate Assessment (RIAA) and draft MCZ Assessment report are provided alongside the PEIR.

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
		statutory protected sites within the study area and/or Zone of Influence that are designated under European Directives and/or implemented through national legislation by a statutory body, thereby having recognised legal protection.	
Natural England	August 2021 Scoping Opinion	**Section 1.5.3** Natural England note the large onshore scoping area and reserve the right to make future detailed comments once the onshore transmission substation location has been confirmed but will endeavour to provide the best advice available with the information currently provided. For information only.	Noted
Natural England	August 2021 Scoping Opinion	**Section 1.5.3 Points 40 - 42** At present, there is no confirmed Grid Connection point from National Grid, and no definitive location of any onshore substation. This presents the risk that the onshore search area may change when the connection point is secured and thus, any studies, surveys and baseline understanding of the onshore aspects of the Project may need to be revised. Should the grid connection point be out with the areas considered within the scoping report it may be necessary to rescope the Project. The decision to scope is one the applicant has undertaken at their own risk, and Natural England reserves the right to amend or update our opinion based on the final grid location, once it is known.	The refined onshore project area assessed in this PEIR remains within the onshore scoping area.
Natural England	August 2021 Scoping Opinion	**Section 1.5.3 Point 42** The list of open matters includes repowering. Repowering is likely to occur near the end of the Project life. As this is likely to be in excess of thirty years from the current scoping we would advise that any repowering should be subject to updated scoping and a full new application.	No repowering works will be included within the DCO application. Should repowering be proposed, further consents would be sought and would be supported by the required environmental information.
Natural England	August 2021	Natural England notes that there remain issues with securing an onshore grid connection and that within the current area of search for	As discussed in Section 5.1, NFOW is engaging with other developers, including National Grid Ventures to explore connection options. At this

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
	Scoping Opinion	landfall, onshore cable route and substation there are likely to be significant nature conservation and landscape challenges. Therefore, we strongly advise that the Project seriously considers utilising National Grid Ventures Nautilus Interconnector as means to address these issues.	stage, the commercial, regulatory and legislative frameworks required to facilitate utilising the Nautilus interconnector (or any other offshore connection) remain uncertain.
Public Health England	August 2021 Scoping Opinion	**Other aspects** Within the ES, PHE would expect to see information about how the applicant would respond to accidents with potential off-site emissions (e.g., flooding or fires, spills, leaks or releases off-site). Assessment of accidents should: identify all potential hazards in relation to construction, operation and decommissioning; include an assessment of the risks posed; and identify risk management measures and contingency actions that will be employed in the event of an accident in order to mitigate off-site effects. PHE would expect the applicant to consider the COMAH Regulations (Control of Major Accident Hazards) and the Major Accident Off-Site Emergency Plan (Management of Waste from Extractive Industries) (England and Wales) Regulations: both in terms of their applicability to the development itself, and the development's potential to impact on, or be impacted by, any nearby installations themselves subject to these Regulations. There is evidence that, in some cases, perception of risk may have a greater impact on health than the hazard itself. A 2009 report13, jointly published by Liverpool John Moores University and the Health Protection Agency (HPA), examined health risk perception and environmental problems using a number of case studies. As a point to consider, the report suggested: "Estimation of community anxiety and stress should be included as part of every risk or impact assessment of proposed plans that involve a potential environmental hazard. This is true even when the physical health risks may be negligible." PHE supports the inclusion of this information within ES' as good practice.	An assessment of the risk of major accidents and/or disasters is provided in Section 5.9. Potential effects on mental health have been considered within Chapter 28 Human Health (Volume I).
Public Health England	August 2021 Scoping Opinion	**Policy Measures for the Electricity Industry** A voluntary code of practice is published which sets out key principles for complying with the [International Commission on Non-Ionizing	The Project intends to comply with *Power Lines: Demonstrating compliance with EMF public exposure guidelines A voluntary Code of Practice* (DECC, 2012).

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
		Radiation Protection] ICNIRP guidelines. Companion codes of practice dealing with optimum phasing of high voltage power lines and aspects of the guidelines that relate to indirect effects are also available	
Planning Inspectorate	August 2021 Scoping Opinion	The ES should include the following: • a description of the Proposed Development comprising at least the information on the site, design, size and other relevant features of the development; and • a description of the location of the development and description of the physical characteristics of the whole development, including any requisite demolition works and the land-use requirements during construction and operation phases	Information on the site and a description of the location of the development is provided in Sections 5.6.1 (offshore), 5.7.1 (landfall) and 5.8.1 (onshore). A description of the physical characteristics of the whole development, including the design and size is provided throughout Sections 5.3 to 5.8. An outline of potential decommissioning works is provided in Sections 5.6.16, 5.8.3.6 and 5.8.4.10. The scope of the decommissioning works would be determined by the relevant legislation and guidance at the time of decommissioning and would be subject to further environmental assessment.
Planning Inspectorate	August 2021 Scoping Opinion	The Scoping Report presents an indicative construction programme for the Proposed Development at Section 1.5.5. This indicates that there is potential for a phased approach to construction, with onshore activity commencing in 2026 prior to offshore activity in 2028. The ES should describe the construction programme, and any phasing in delivery, including the expected duration and overlap of different components to enable an assessment of the effects on the basis of a worst case scenario.	The construction programme is discussed in Sections 5.6.13 and 5.8.5.
Planning Inspectorate	August 2021 Scoping Opinion	The anticipated generating capacity of the Proposed Development is not stated in the Scoping Report, although paragraph 5 explains that the expected capacity is greater than 100 MW. The maximum technical capacity (i.e., electrical output) of the individual WGTs and of the Proposed Development as a whole should be confirmed within the ES.	The generating capacity is discussed in Section 5.5.
Planning Inspectorate	August 2021 Scoping Opinion	The Scoping Report provides limited information about the operational and maintenance activities for the operational phase of the Proposed Development. The ES should provide a full description of the nature and scope of these activities, including types of activity, frequency, and how works will be carried out for both offshore and onshore components. This should include consideration for the potential	The North Falls operation and maintenance activities are discussed in Section 5.6.14. Where relevant, the cumulative effects of ongoing operation and maintenance of GGOW and GWF with North Falls are considered in Chapters 8 to 18 (Volume I).

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
		overlapping of activities with those required for the continuing operation of GGOW and GOWF.	
Planning Inspectorate	August 2021 Scoping Opinion	Paragraph 90 of the Scoping Report confirms that the ES will consider the potential for impacts during decommissioning of the Proposed Development, but limited information is provided about the physical characteristics associated with this activity. Most of the subsequent aspect sections of the Scoping Report also address decommissioning in respect of the Proposed Development, noting that activities would be similar to those during the construction phase without describing the activities in detail. The ES should include a description of the anticipated decommissioning activities and their likely duration. Where there is uncertainty of impacts during decommissioning, this should be clearly explained along with the implications for the assessment of significant effects (including assumptions and mitigation on which reliance is placed).	A description of decommissioning activities is provided in Sections 5.6.16, 5.8.3.6 and 5.8.4.10.
Planning Inspectorate	August 2021 Scoping Opinion	Section 1.5.4 of the Scoping Report states that port facilities will be required to support the construction and operation of the Proposed Development, and it is likely that the port will be located on the east coast of England. The ES should make effort to identify the location of the port(s), where possible, and assess any likely significant effects associated. In the event that the port(s) have not been confirmed, the ES should make effort to assess the likely significant effects associated with relevant assumptions and a worst case scenario. The worst case parameters applied in relation to port location(s) should be clearly defined and consistently applied across the relevant assessments in the ES.	The port location(s) will be identified post consent. This approach is standard for offshore wind farms, due to commercial and procurement constraints. Where port assumptions are required to inform the assessment, the worst case scenario is described in the relevant technical chapters.
Planning Inspectorate	August 2021 Scoping Opinion	The ES should include a description of the nature and quantity of materials and natural resources used in the Proposed Development, including water, land, soil and biodiversity.	Information regarding the quantity of materials and natural resources (e.g. scour protection and rock protection) is considered in this PEIR and assumptions will be revisited in the Project's ES.
Planning Inspectorate	August 2021 Scoping Opinion	The layout of Wind Turbine Generators (WTGs), including the division of WTGs between the two proposed array areas, has not yet been ascertained and it is stated that this will be determined following site investigation post consent (paragraph 28 of the Scoping Report). Table 1.1 states that there will be a maximum of 71 WTGs. In	The design envelope of WTGs is provided in Section 5.6.3.1. Indicative layouts are included in the assessments where applicable, namely Chapter 29 Seascape, landscape and visual impact assessment (SLVIA) (Volume I).

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
		addition, paragraph 27 of the Scoping Report identifies a possibility that more than one model of WTG may be used. The ES should include a full and detailed description of the potential WTG models and the parameters associated with their design (including distance between WTG), as well as establishing and assessing the layout(s) that result in the worst case adverse effects.	
Planning Inspectorate	August 2021 Scoping Opinion	The Scoping Report explains that the array cables used to connect the WTGs to the offshore substation will be between 33kV and 132kV but not the process by which the final voltage would be chosen. The ES should describe these options, any differences in the physical infrastructure requirements and provide an assessment of environmental effects that may result from the selected options.	The final voltage will be selected based on technical feasibility, regulatory issues and environmental impact at the time of selection. Should different options be retained at DCO application stage, the worst case infrastructure required for the options will be assessed within the Project's ES.
Planning Inspectorate	August 2021 Scoping Opinion	Paragraph 29 of the Scoping Report states that the design of foundations for the WTGs and platforms will be informed by site investigation post consent, and that it is possible that more than one type of foundation will be used. The following foundation design options are being considered: monopiles, jackets on pins or suction caissons, and gravity base structures (GBS). Table 1.2 of the Scoping Report sets out indicative dimensions and construction materials for the range of options. The ES should include a full and detailed description of foundation options and any scour protection for which development consent is sought, including the location, maximum diameter and depth, and the maximum diameter of piles should they be used.	A description of the range of foundation options is provided in Section 5.6.3.3.
Planning Inspectorate	August 2021 Scoping Opinion	The Inspectorate notes that the preferred options for landfall location of the export cables, location of the onshore substation and routeing of the underground cables will be refined and selected during the assessment process (paragraphs 37 and 51 of the Scoping Report). The Inspectorate understands that the onshore location and routeing will in part be determined based on the selected location of the East Anglia Coastal transmission substation, which is the subject of a separate consenting process by National Grid. The ES should describe the preferred options for landfall and onshore components of the Proposed Development, including the location and maximum design parameters of each component (footprint, height, width, depth and volume as relevant). It should explain the relationship between	A description of the landfall and onshore components is provided in Sections 5.7 and 5.8.

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
		the preferred options and the East Anglia Coastal transmission substation, the status of the separate project, any uncertainty remaining if it is not yet finalised and how that has been addressed in the assessment presented in the ES.	
Planning Inspectorate	August 2021 Scoping Opinion	As the landfall and onshore components are still subject to areas of search, the Inspectorate notes that it is not yet clear whether any temporary or permanent crossings of watercourses, major roadways and / or railways will be required as part of the Proposed Development, nor is any information presented as to the proposed methodology that would be used for such crossings. The ES should identify the locations and types of all such crossings. Where reliance is placed in the ES on the use of a specific method as mitigation, the Applicant should ensure that such commitments are appropriately defined and secured.	A Crossing Schedule is provided as an Appendix to this chapter (Appendix 5.1, Volume III). This schedule lists all the proposed obstacle crossings required to facilitate construction of the Projects landfall and onshore infrastructure, and sets out the range of techniques being proposed at each at this stage in the Project's design.
Planning Inspectorate	August 2021 Scoping Opinion	The EIA Regulations require an estimate, by type and quantity, of expected residues and emissions. Specific reference should be made to water, air, soil and subsoil pollution, noise, vibration, light, heat, radiation and quantities and types of waste produced during the construction and operation phases, where relevant. This information should be provided in a clear and consistent fashion and may be integrated into the relevant aspect assessments.	Expected emissions predicted to arise during the construction and operational of the Project are detailed in this chapter (Sections 5.6 - 5.8) the relevant technical chapters (Volume I), including: • Chapter 19 Ground Conditions and Contamination • Chapter 20 Air Quality • Chapter 21 Water Resources and Flood Risk • Chapter 26 Noise and Vibration
Planning Inspectorate	August 2021 Scoping Opinion	The Inspectorate notes that the Scoping Report does not make reference to the potential for any emissions in respect of radiation during the construction, operational or decommissioning phases of the Proposed Development. Given the nature of the Proposed Development as an offshore wind farm and associated infrastructure, the Inspectorate considers that significant effects from radiation would not be likely and the ES does not need to reference this matter.	Noted. The Applicant also notes that Electromagnetic Forces and their potential to be generated during the Project's operation are discussed in Chapter 28 Human Health (Volume I).
Planning Inspectorate	August 2021 Scoping Opinion	The ES should include a description and assessment (where relevant) of the likely significant effects resulting from accidents and disasters applicable to the Proposed Development. The Applicant should make use of appropriate guidance (e.g., that referenced in the Health and Safety Executives (HSE) Annex to the Inspectorate's Advice Note 11) to better understand the likelihood of an occurrence and the Proposed	An assessment of the risk of major accidents and/or disasters is provided in Section 5.9.

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
		Development's susceptibility to potential major accidents and hazards. The description and assessment should consider the vulnerability of the Proposed Development to a potential accident or disaster and also the Proposed Development's potential to cause an accident or disaster. The assessment should specifically assess significant effects resulting from the risks to human health, cultural heritage or the environment. Any measures that will be employed to prevent and control significant effects should be presented in the ES. Relevant information available and obtained through risk assessments pursuant to national legislation may be used for this purpose. Where appropriate, this description should include measures envisaged to prevent or mitigate the significant adverse effects of such events on the environment and details of the preparedness for and proposed response to such emergencies.	
Planning Inspectorate	August 2021 Scoping Opinion	Section 4.5 of the Scoping Report sets out the Applicant's proposed approach to assessment of major accidents and disasters. It is stated that following a review of potential major accidents and disasters, a number of matters are proposed to be scoped into the ES as part of other aspect chapters, including coastal erosion and flood risk, accidental spills of hazardous materials, vessel collision and exposed cables leading to vessel snagging. The Inspectorate agrees that these matters should be scoped into the ES and can be considered as matters within relevant aspect assessments.	Effects on coastal erosion are considered in Chapter 8 Marine Geology, Oceanography and Physical Processes (Volume I). Effects on flood risk are considered in Chapter 21 Water Resources and Flood Risk (Volume I). Accidental spills of hazardous materials are considered in Section 5.9 of this chapter. Potential vessel collisions and exposed cables leading to vessel snagging is assessed in Chapter 15 Shipping and Navigation (Volume I).
Planning Inspectorate	August 2021 Scoping Opinion	The Scoping Report states that a standalone assessment of major accidents and disasters is proposed to be scoped out of the ES on the basis that likely significant effects arising from this aspect associated with coastal erosion and flood risk, accidental spills of hazardous material, vessel collision and exposed cables leading to vessel snagging will be considered within the relevant aspect chapters. The Applicant states that a review of potential for major accidents and disasters has been undertaken and no other likely significant effects have been identified; however, the outcome of this review is not included within the Scoping Report. The Inspectorate does not consider that sufficient information has been presented within the Scoping Report to conclude that there would be no likely significant effects from other potential major	An assessment of the risk of major accidents and/or disasters is provided in Section 5.9.

Consultee	Date / Document	Comment	Response / where addressed in the PEIR
		accidents and disasters, both in respect of the vulnerability of the Proposed Development to these or for the Proposed Development to cause them. The results of the review exercise completed by the Applicant should be presented in the ES. This should include a description of the sources of hazards and pathways that have been considered as part of the review process and why these have been discounted. Where likely significant effects are identified, these should be assessed in the ES. In this regard, the Inspectorate notes that there is potential for wartime UXO to be located within the offshore scoping area and no information has been presented about their locations and potential for accidental detonation and associated impacts that could lead to a major accident or disaster. In addition, the potential for cumulative effects arising from major accidents and disasters in terms of inter relationships with other aspects of the Proposed Development and other projects should be considered, and where significant effects are likely to occur, these should be assessed within the ES.	

5.3 Outline of the Project components

8. The key offshore components considered in this PEIR comprise:

- Wind turbine generators (WTG) and their associated foundations;
- Up to two offshore substation platforms (OSP) and their associated foundations to facilitate the export of electricity via the Project's offshore export cables;
- Subsea cables:
  - Array cables between the WTGs and OSP(s);
  - Interconnector cable between the northern and southern array areas; and
  - Export cables between the OSP(s) and landfall; and
- Scour protection around foundations and subsea cables where required.

9. The key onshore components considered in this PEIR comprise:

- Landfall;
- Onshore export cables and associated link boxes;
- Onshore substation; and
- Connection to the national grid.

5.4 Project design envelope

10. The North Falls Environmental Impact Assessment (EIA), reported in this PEIR, will be based on a design envelope approach in accordance with National Policy Statement (NPS EN-3; paragraph 2.6.42) which recognises that: "*Owing to the complex nature of offshore wind farm development, many of the details of a proposed scheme may be unknown to the applicant at the time of the application, possibly including:*

- "Precise location and configuration of turbines and associated development;
- Foundation type;
- Exact turbine tip height (and rotor diameter);
- Cable type, number of cables and cable route; and
- Exact number and locations of offshore and onshore substations."

11. NPS EN-3 (paragraph 2.6.43) continues: "The [Secretary of State] should accept that wind farm operators are unlikely to know precisely which turbines will be procured for the site until sometime after any consent has been granted. Where some details have not been included in the application to the [Secretary of State], the applicant should explain which elements of the scheme have yet to be finalised, and the reasons. Therefore, some flexibility may be required in the consent. Where this is sought and the precise details are not known, then the applicant should assess the effects the Project could have […] to ensure

that the Project as it may be constructed has been properly assessed (the Rochdale [Design] Envelope)". (DECC, 2011)

12. The design envelope is therefore based on maximum and minimum parameters, where appropriate, to ensure the worst case scenario can be quantified and is assessed in the EIA. The final design of North Falls will lie within the range of parameters assessed in the EIA and detailed in this chapter. Each technical chapter (Chapters 8 to 34, Volume I) of this PEIR outline the relevant worst case scenario, noting that this will vary depending on the receptor and impact being considered. For example with regards to WTG foundations (see Section 5.6.3.3), the worst case scenario for underwater noise would be based on foundations installed using pile driving, whereas the worst case scenario for habitat loss would be based on gravity base foundations with the largest seabed footprint.

13. This approach has been widely successful in the consenting of OWFs and is consistent with the Planning Inspectorate Advice Note Nine: Rochdale Envelope (Planning Inspectorate, 2018) which states that: "*The Rochdale Envelope assessment approach is an acknowledged way of assessing a Proposed Development comprising EIA development where uncertainty exists and necessary flexibility is sought*".

5.4.1 Grid connection optionality

14. As noted in Section 5.1, at this stage of the Project's development, some optionality is required in order to future-proof the DCO.

15. One area of optionality is in relation to the National Grid connection point. As discussed in Chapter 1, NFOW is committed to working with the Department for Energy Security and Net Zero (DESNZ) to explore grid connection options as part of the Offshore Transmission Network Review (OTNR) process. NFOW has committed to exploring coordinated network designs, along with four other projects in East Anglia: Five Estuaries, National Grid Electricity Transmission's Sea Link, and National Grid Ventures' EuroLink and Nautilus. As such, NFOW is currently reviewing the following options for the Project's National Grid connection point:

- Option 1: Onshore electrical connection at a National Grid connection point within the Tendring peninsula of Essex (discussed in Section 5.8), with a project alone onshore cable route and onshore substation infrastructure;
- Option 2: Onshore electrical connection at a National Grid connection point within the Tendring peninsula of Essex, sharing an onshore cable route (but with separate onshore export cables) with another project (i.e., Five Estuaries), where practicable; or
- Option 3: Offshore electrical connection, supplied by a third party electricity distribution network provider. Such a connection will potentially be identified through the OTNR process, in which NFOW is actively engaged.

16. The preliminary EIA presented in the North Falls PEIR is based on the design parameters and assumptions for Option 1. This is because, in general, Option 1 is considered to be the worst case for construction of the Project and its connection to the national grid. Chapters 8 to 33 (Volume I) provide further detail on the relevant worst case scenario for each impact for this option.

17. For onshore works under Option 2, the North Falls infrastructure required is the same as for Option 1, however activities that are common to both North Falls and the second project (i.e., Five Estuaries) can be optimised and shared. This includes items such as the number of construction compounds along the onshore cable route, which will be shared between the projects, preventing unnecessary duplication of similar infrastructure or removal of items that could be used by a second project constructing sequentially with the first. This results in North Falls' share of construction metrics (number of plant required, volume of vehicle movements required, etc.) for Option 2 being equal to or lower than the corresponding Option 1 metric in most cases. For example, metrics such hedgerow removal will be the same between Options 1 and 2 as this has been minimised for the standalone project, and there is no change to the permanent easement required for North Falls under Option 2; whilst the total vehicle movement numbers for construction activities will be lower under Option 2, as the construction activities can be optimised and shared between the two projects.

18. However, in certain situations onshore, Option 2 may be the worst case. Generally, this will relate to construction durations, where project optimisation means certain elements of the works, for example HDD or temporary construction compounds, will remain in place for an extended duration under Option 2 than they would under Option 1. Whereas under Option 1 these compounds would be taken up and the end of construction for North Falls and an alternative used for the construction of a second project (i.e., Five Estuaries), under Option 2 these would be potentially used by both projects sequentially and therefore require works in one area for an extended duration. Whilst peak volumes of equipment use / vehicle movements for an individual project will remain the same, optimisations, as described above, mean that the overall numbers in most instances can be reduced.

19. For offshore works, there is little difference between Option 1 and Option 2. The potential for optimising construction between two projects would only take place during onshore construction.

20. For Option 3, no onshore works would be required and most or all of the offshore cable corridor would no longer be required, therefore the impacts would primarily relate to the offshore array areas only. Option 3 may be worst case for employment benefits and socioeconomic benefits due to the reduction in infrastructure required.

21. Further details regarding the determination of the 'worst case' for assessment within this PEIR for each EIA topic is provided in Appendix 6.1 Grid Connection Optionality – Worst Case Assessment (Volume III).

22. It should be noted that Options 1 and 2, with a connection point within the Tendring peninsula of Essex, are currently the only grid options provided by National Grid and therefore available to North Falls.

23. In relation to Option 2, NFOW and Five Estuaries Offshore Wind Farm Ltd are exploring potential co-ordination of construction, infrastructure and operations plans of North Falls and the nearby Five Estuaries offshore wind farm, however

these are two distinct projects with separate ownership/shareholders[1]. Discussions will continue during the Project development phase to seek opportunities for collaboration where this is considered practicable and feasible. Collaboration with other projects would be considered, where applicable.

24. At this stage the commercial, regulatory and legislative frameworks required to facilitate Option 3 are not currently in place, although they are being reviewed as part of the OTNR.

25. Alongside the complex grid-related processes, North Falls has an imperative to meet its operational date to contribute to the government's 2030 targets. For these reasons, to avoid project delays, North Falls cannot currently commit to Option 3, however NFOW continues to engage with other developers, Government and Ofgem to explore the other potential options.

5.5 Generation capacity

26. The DCO application for North Falls will not include a maximum generating capacity cap for the purposes of consent. This is to maintain flexibility in the Project design and to allow the Applicant to seek to maximise the capacity of North Falls to meet the urgent need for renewable electricity generation post-consent. An increase in capacity can be achieved without increasing the Project boundary or project parameters as a result of the rapid development in WTG technology.

27. For most assessments, the generating capacity is irrelevant to the environmental effects associated with North Falls. The EIA reported in this PEIR therefore assesses the maximum physical size or maximum number of WTGs (subject to the worst case scenario for each receptor) and associated infrastructure. Where required, an indicative generating capacity of 504MW to 1000MW (1GW) is considered within the EIA.

28. This approach is consistent with other recently made offshore wind DCOs including the Hornsea Three Offshore Wind Farm Order 2020, the East Anglia ONE North Offshore Wind Farm Order 2022 and the East Anglia Two Offshore Wind Farm Order 2022.

5.6 Offshore

5.6.1 Offshore location

5.6.1.1 *Array areas*

29. The North Falls array area is split into two boundaries to facilitate a shipping route, discussed further in Chapter 15 Shipping and Navigation (Volume I). Other existing infrastructure and users in the area are described in Chapter 18 Infrastructure and Other Users (Volume I).

30. The northern and southern array boundaries cover areas of approximately 20.9km^2 (6.1nm^2) and 128.6km^2 (37.5nm^2), respectively. At closest point, the northern array boundary lies approximately 22.5km (12.1nm) from shore, and

[1] The UK Government Contract for Difference auction framework (discussed further in Chapter 3 Policy and Legislative Context, Volume I) necessitates competition amongst projects.

the southern boundary approximately 37.6km (20.3nm) from shore. The site boundaries are shown on Figure 1.1 (Volume II).

31. Water depths within the array areas range from 5m to 59m (relative to the Lowest Astronomical Tide (LAT)), with a mean depth of 30mLAT. The substrate in the array areas is dominated by sandy gravel/ gravelly sand (discussed further in Chapter 8 Marine Geology Oceanography and Physical Processes, Volume I). Mobile sand waves of up to 13m peaks are present in parts of the array areas.

32. The array areas are located within the Southern North Sea Special Area of Conservation (SAC) and there is a small area of overlap between the southern array area and the Kentish Knock East Marine Conservation Zone (MCZ). The range of constraints considered in the selection of the array areas are discussed in Chapter 4 Site Selection and Assessment of Alternatives of this PEIR (Volume I).

5.6.1.2 *Offshore cable corridor*

33. The electricity will be connected to the shore by export cables which will be located within an offshore cable corridor which runs from the southern array area to the landfall location (Section 5.7.1).

34. The majority of the offshore cable corridor is less than 30mLAT in water depth and the substrate is predominantly sandy gravel/gravelly sand, with some mud content in the nearshore areas. Mobile sand waves of up to 7m peaks are present in parts of the offshore cable corridor.

35. The offshore cable corridor passes to the north, and outside of the Margate and Long Sands SAC and Kentish Knock East MCZ, with a small overlap with the Outer Thames Estuary Special Protection Area (SPA) as it approaches landfall. The range of constraints considered in the routing of the offshore export cable corridor are discussed in Chapter 4 Site Selection and Assessment of Alternatives of this PEIR (Volume I).

5.6.2 Offshore project details summary

Table 5.2 Offshore project characteristics

Feature	Worst case parameters
Number of WTGs	72
Array areas	150km^2
Distance to shore (closest distance)	22.5km
Offshore cable corridor length	57km
No. of export cable circuits	4
Target minimum cable burial depth (where buried)	0.5-3m
Maximum WTG rotor diameter	337m
Maximum rotor tip height	397m above Mean High Water Springs (MHWS)
Minimum clearance above sea level	27m above MHWS
Minimum separation between WTGs	1150m downwind; 820m cross wind
No. of offshore substation platforms (OSP)	2

Feature	Worst case parameters
Maximum array cable length (includes interconnector cable)	228km

5.6.3 Offshore infrastructure

5.6.3.1 *Wind turbine generators*

36. This section provides a description of the WTG options considered for North Falls and the parameters that the PEIR assessment is based on. Conventional three bladed, horizontal axis WTGs will be used, comprised of the following main components, and illustrated in Plate 5.1.

- Rotor, comprising:
  - Blades;
  - Hub - connects the blades to the main shaft and ultimately to the rest of the drive train;
- Nacelle - houses the electrical generator, control electronics and drive system (Plate 5.2); and
- Structural support - tubular steel tower atop a foundation structure.

37. Options for minimum and maximum WTG size and the associated characteristics being considered in this PEIR are provided in Table 5.3.

Table 5.3 Project design envelope WTG parameters

Parameter	Value for smallest turbines	Value for largest turbines
Maximum number for indicative size	72	40
Minimum rotor diameter (m)	164	200
Maximum rotor diameter for indicative size (m)	250	337
Maximum blade tip height above MHWS (m)	310	397
Minimum lower blade tip height above MHWS (m)	27m	
Indicative nominal rotations per minute(rpm)	8	6
Minimum hub height above MHWS (m)	109	N/A
Maximum hub height above MHWS (m)	N/A	220

38. At this stage, wind turbine types have not been determined. There is potential that the site could host more than one wind turbine type/model, all within the parameters outlined above

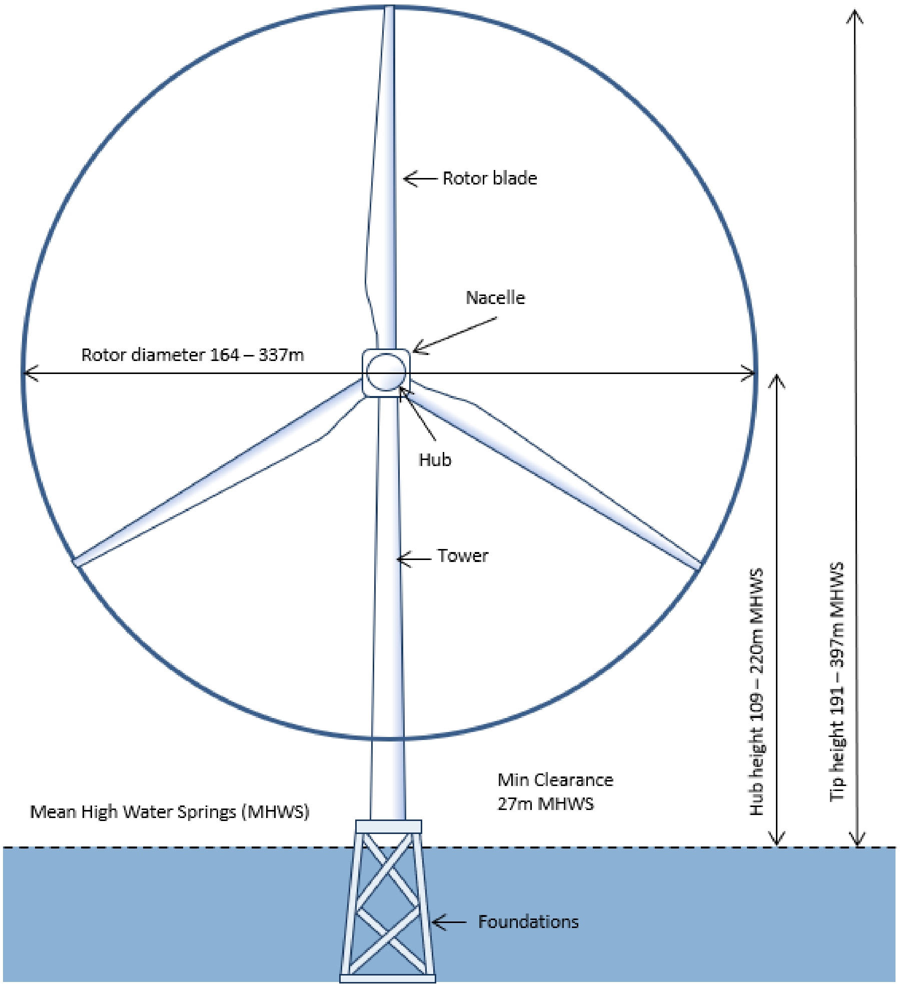

Plate 5.1 Key WTG dimensions

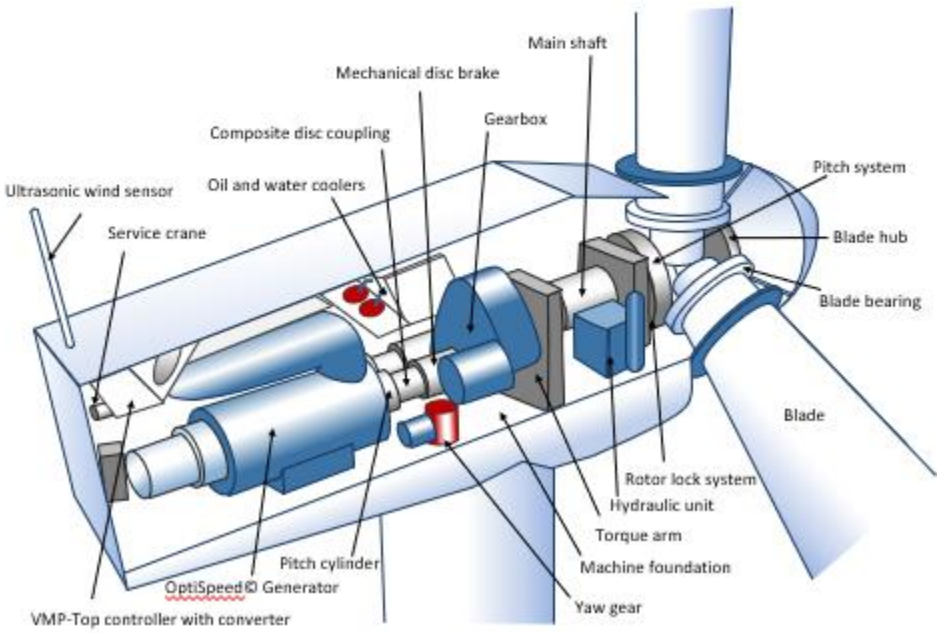

Plate 5.2 Indicative nacelle components

5.6.3.2 *Wind turbine layout*

39. The eventual layout of the wind farm would be decided post-consent, taking into account wind resource, ground conditions identified by site investigation works, navigational requirements and the size of turbine selected. Turbine size selection is driven by commercial factors, and market conditions at the time. In developing the final layout, the Applicant would aim to minimise environmental impacts (e.g. through micro-siting) and impacts to other users whilst maximising energy yield and cost efficiency. Therefore, exact locations will not be included in the DCO application.

40. The wind turbine layout can be described in general terms at this stage. The minimum separation between wind turbines would be approximately of 5 x the rotor diameter (i.e. 820m for the smallest turbines with 164m rotor diameter or 1,685m for the largest turbines with 337m rotor diameter).

5.6.3.3 *Foundations and substructures*

41. This section provides detail on the foundations and substructures that are assessed in this PEIR for the Project. The decision on the types of foundation and substructure to support the WTGs and offshore substation platform(s) will be made post-consent. Foundation types will be selected following detailed design, based on suitability of the ground conditions, water depths and wind turbine models. There may be only one type used, or a combination of foundation types may be used across the array areas.

42. The foundation types currently being considered for use are:

- Monopile (Plate 5.3)
- Mono suction bucket (Plate 5.4)
- Gravity base system (GBS) (Plate 5.5);
- Jacket with 3 or 4 legs (Plate 5.6) attached to the seabed by:
    - Pin-piles;
    - Suction buckets; and
    - Gravity/ballast legs.

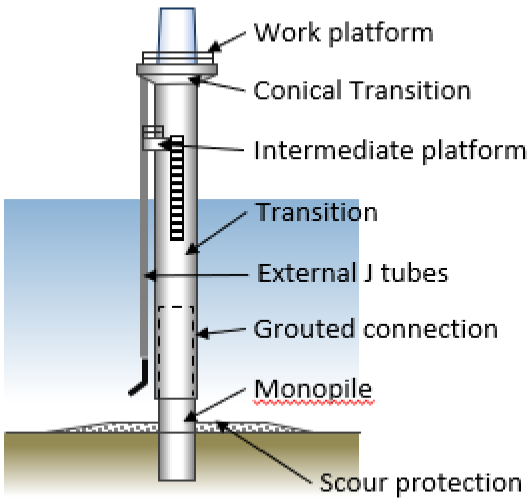

Plate 5.3 Typical monopile

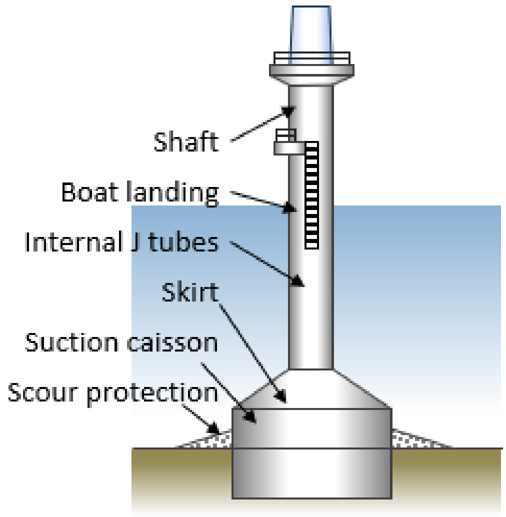

Plate 5.4 Typical suction bucket

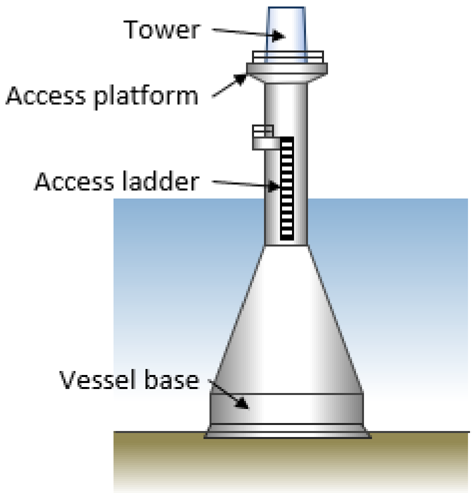

Plate 5.5 Typical gravity-based structure

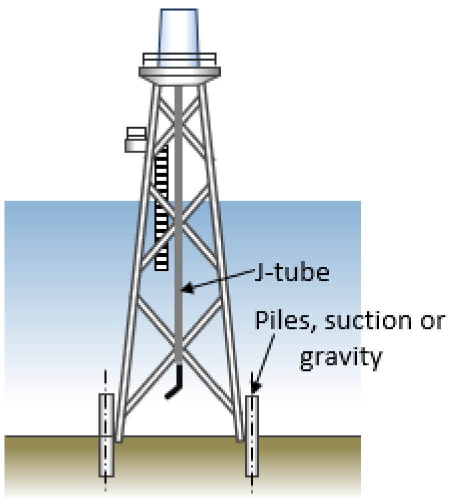

Plate 5.6 Typical jacket structure

5.6.3.3.1 Monopile

43. Monopile foundations can be driven using a hydraulic hammer ('piling'), or a combination of piling and drilling. Monopiles are normally constructed from welded tubular steel sections, however additional materials such as metals, aluminium or composites may be used for secondary structures such as ladders, handrails etc. The piles support the weight of the tower and turbine and rely on the surrounding geology to provide lateral resistance to horizontal forces such as wind and waves. The WTG tower will be connected to the monopile structure with a transition piece installed over or inside the monopile, typically connected to the WTG tower using grout.

44. Drilling may also be required at up to 10% of the site if monopile foundations are chosen. Monopile parameters including drill arisings related to monopiles are included in Table 5.4.

Table 5.4 Monopile design parameters

Parameter	Value for smallest turbines	Value for largest turbines
Piles		
Maximum number of piles	72	40
Maximum pile diameter (m)	12	17
Indicative pile penetration depth (m)	38	42
Maximum hammer energy (kJ)	6,000	
Drilling (if required)		
Indicative drill penetration depth (m)	38	42
Maximum drill diameter (m)	13	18
Maximum volume arisings per pile (m^3)	5,044	10,688
Average drill arisings per pile	4,298	9,533
Proportion of foundations requiring drilling	10%	
Total volume of WTG arisings (m^3)	31,128	38,133

5.6.3.3.2 Mono suction bucket

45. Suction caissons may comprise a single steel cylindrical tower (the shaft), a transition structure (the lid) and cylindrical skirt which penetrates into the seabed. Parameters for the suction caisson foundations are outlined in Table 5.5 below.

Table 5.5 Mono suction bucket parameters

Parameter	Value for smallest turbines	Value for largest turbines
Maximum number of suction buckets	72	40
Maximum bucket diameter (OD) (m)	38	
Indicative bucket penetration depth (m)	25	
Suction bucket height above seabed (m)	10	

5.6.3.3.3 Gravity Base Structure (GBS)

46. There are many possible shapes and sizes being proposed by manufacturers for GBS. GBS usually comprise a base, a conical section and a cylindrical section (Plate 5.5). Usually the base is hexagonal, octagonal or circular. Footprint sizes for the base are outlined in Table 5.6.

Table 5.6 GBS parameters

Parameter	Value for smallest turbines	Value for largest turbines
Maximum number of foundations	72	40
Maximum diameter (m)	65	
Seabed Preparation Diameter (m)	70	
Gravity based height above seabed (m)	15	

5.6.3.3.4 Jacket with pin-piles

47. Jacket substructures are a steel lattice construction (tubular steel and welded joints) secured to the seabed either by hollow steel pin-piles (either driven or drilled depending on the geology), gravity base or suction buckets.

48. The design envelope for jacket substructures is shown in Table 5.7.

Table 5.7 Pin-piled jacket design parameters

Parameter	Value for smallest turbines	Value for largest turbines
Maximum number of foundations	72	40
Maximum number of pin piles per jacket	4	
Maximum number of pin piles	288	160
Maximum pin pile diameter (m)	3.5	
Maximum hammer energy (kJ)	3,000	
Drilling (if required)		
Indicative drill penetration depth (m)	38	42
Maximum drill diameter (m)	3.5	3.5
Maximum volume arisings per pile (m^3)	365.6	404
Maximum volume arisings per foundation (m^3)	1,462	1,616
Proportion of foundations requiring drilling	10%	
Total volume of arisings (m^3)	10,237	6,464

5.6.3.4 Jacket with suction buckets

49. A jacket foundation on suction caissons may be used. This would consist of a jacket, that would be installed on three or four suction caisson 'legs'. Parameters for the suction caisson foundations are outlined in Table 5.8 below.

Table 5.8 Jacket with suction bucket parameters

Parameter	Value for smallest turbines	Value for largest turbines
Maximum number of buckets (based on 4 leg jacket)	288	160
Maximum bucket diameter (m)	15	23
Separation of adjacent legs at seabed (m)	60	
Separation of adjacent legs at sea surface (m)	50	
Suction bucket height above seabed (m)	1.5	

5.6.3.5 Jacket with gravity/ballast legs

50. A jacket foundation on gravity/ballasted legs may be used. This would consist of three or four gravity 'legs'. Footprint sizes for the gravity legs are outlined in Table 5.9.

Table 5.9 Gravity base design parameters

Parameter	Value for smallest turbines	Value for largest turbines
Maximum number of gravity legs (based on 4 leg jacket)	288	160
Maximum base diameter (m)	23	
Seabed Preparation Diameter (m)	25	
Gravity based height above seabed (m)	15	

5.6.3.6 *Offshore substation platform*

51. North Falls will require a maximum of two offshore substation platforms (OSP)s (Plate 5.7) depending on the electrical system voltage and final layout. The OSPs provide a connection point for the array cables and contain primary electrical equipment and ancillary components that are required to transform the voltage of the electricity generated at the WTGs to a higher voltage suitable for transporting power to the onshore electrical transmission network.

Plate 5.7 Example OSP (image courtesy of RWE Renewables)

52. The offshore platforms are likely to contain a combination of one or more of the following facilities:

- Cooling systems;

- Medium voltage (MV) to high voltage (HV) step-up power transformers;
- HV Reactors;
- MV and/or HV switchgear;
- Other electrical power systems;
- Instrumentation, metering equipment and control systems;
- Standby generators;
- Auxiliary and uninterruptible power supply systems;
- Navigation, aviation, and safety marking and lighting;
- Helicopter landing facilities;
- Systems for vessel access and/or retrieval;
- Vessel and helicopter refuelling facilities;
- Potable water;
- Black water separation;
- Storage (including stores, fuel, and spares);
- Cranes; and
- Communication systems and control hub facilities.

53. The location of the OSP(s) will be confirmed during the post DCO detailed design process. The design of the OSP(s) will include a platform ‘topside’, supported above sea level on a foundation structure. Foundation options include either monopile (drilled, driven, or suction bucket) or jackets (with either pin piles, suction bucket or gravity based monopiles). Topside and substructure design parameters for the OSP(s) are shown in Table 5.10.

Table 5.10 OSP(s) topside and substructure design parameters

Parameter	1 substation 2 substations
Maximum topside length (m)	80
Maximum topside width (m)	50
Maximum topside height (m) (excluding crane and helideck)	+68.23m above MHWS
Maximum topside height (m) (including crane and communications antennas)	+118.23m above MHWS
Monopiles	
Maximum column diameter (m)	17
Hammer energy required (for pile driving) (kJ)	6,000
Indicative drill penetration depth (m)	42
Maximum drill diameter (m)	18
Maximum volume arisings per foundation (m^3)	10,688
Proportion of foundations requiring drilling	50%
Total volume of arisings (m^3)	10,688
Mono suction bucket	

Parameter	1 substation	2 substations
Number of monopiles	4	8
Maximum suction bucket diameter (OD) (m)	28	
Indicative bucket penetration depth (m)	25	
GBS		
Max diameter (m)	60	
Seabed preparation diameter (m)	65	
Gravity based height above seabed (m)	15	
Pin-piled jacket		
Number of legs	8	16
Separation of adjacent legs at seabed level (m)	80 x 50	
Separation of adjacent legs at LAT (m)	35 x 40	
Pin pile diameter (m)	3.5	
Maximum hammer energy (kJ)	3000	
Indicative drill penetration depth (m)	60	
Maximum drill diameter (m)	3.5	
Maximum volume arisings per pile (m^3)	577.3	
Maximum volume arisings per foundation (m^3)	4,618	
Proportion of foundations requiring drilling	100	
Total volume of arisings (m^3)	4,618	9,236
Suction bucket jacket		
Number of buckets	6	12
Separation of adjacent legs at seabed level (m)	40 x 50	
Separation of adjacent legs at sea surface (m)	35 x 40	
Max bucket diameter (OD) (m)	25	
Indicative bucket penetration depth (m)	17	
Suction bucket height above seabed (m)	1.5	
Jacket with gravity legs		
Number of gravity legs	6	12
Max diameter (m)	60	
Seabed preparation diameter (m)	65	
Gravity based height above seabed (m)	15	

5.6.3.7 *Scour protection for substructures*

54. Foundations may require scour protection to avoid sediment being eroded away from the base of the foundations as a result of the flow of water. The exact

requirements will be identified post consent, prior to the start of construction, based on the final WTG and OSP locations and detailed site surveys. Purpose made vessels (Plate 5.8) are used to accurately install rock, which is normally completed using a fall-pipe lay system.

Plate 5.8 Indicative scour protection deployment vessel (source: Jan De Nul Group, 2023)

55. Typical options for scour protection include one, or a combination of the following examples:

- Rock or gravel placement;
- Concrete mattresses;
- Flow energy dissipation devices (used to describe various solutions that dissipate flow energy and entrap sediment, and including options such as frond mats, mats of large-linked hoops, and structures covered with long spikes). It is noted that these technologies are often only appropriate for use in areas with significant mobile seabed sediments, and examples such as the spiked designs are only appropriate for use in areas which are not trawled;
- Protective aprons or coverings (solid structures of varying shapes, typically prefabricated in concrete or high-density plastics); and
- Bagged solutions, (including geotextile sand containers, rock-filled gabion bags or nets, and grout bags, filled with material sourced from the site or elsewhere).

56. The maximum diameter, area and volume requirements for scour protection per foundation are provided in Table 5.11. The overall maximum volume of scour protection for the Project is associated with the GBS foundation.

Table 5.11 Scour protection quantities

Parameters	Monopile	Mono suction bucket	Suction jacket	GBS	Gravity jacket legs	Piled jacket
Max diameter at top of scour protection (incl. foundation structure) [m]	80.0	190.0	115.0	325.0	115.0	17.5
Max outer scour protection diameter at seabed (incl. foundation structure) (m)	88.0	198.0	123.0	333.0	123.0	25.5
Max scour protection area per foundation (excl. structure footprint area (m^2)	5,881	29,657	45,867	83,774	45,867	2,004
Max scour protection area per foundation (incl. structure footprint area) (m^2)	6,082	30,791	47,529	87,092	47,529	2,043
Max project scour protection area % of project area	0.3	1.4	2.2	4.0	2.2	0.1
Wind farm seabed area affected (km^2)	0.4	2.1	3.3	6.1	3.3	0.2
Max scour protection volume per foundation (m^3) (rock)	10,681	56,850	21,413	163,388	21,413	707
Max scour protection volume for project (rock) (m^3)	773,640	4,117,583	1,550,920	11,833,956	1,550,920	51,197

5.6.3.8 *Subsea cables*

5.6.3.8.1 Array and interconnector cables

57. HVAC array cables will link together the WTGs, back to the OSP(s), if used (see Section 5.6.3.4). An interconnector cable will also link the northern and southern array areas.

58. Buried array/ interconnector cable parameters are included in Table 5.12. Information on potential cable protection requirements for unburied cable is provided in Section 5.6.3.8.3.

Table 5.12 Array and interconnector cables parameters

Parameter	Value
System voltage (kV)	33-132
Indicative external cable diameter (mm)	220
Average Burial Depth (m)	1.2
Maximum potential length of array/interconnector cable (km)	228
Width of trench by installation per m	1
Spoil volume (m^3)	273,600
Total seabed disturbed (km^2)	0.23
Maximum length of surface laid cable (km)	45.6 (20% of cable length)

5.6.3.8.2 Offshore HVAC export cables

59. Export cables carry power from the array back to the landfall, and then in turn onto the onshore high voltage alternating current (HVAC) export cable. Buried export cable parameters are included in Table 5.13. Information on potential cable protection requirements for unburied cable is provided in Section 5.6.3.8.3.

Table 5.13 Offshore export cables parameters

Parameter	No substation	1 Substation	2 Substations
Max number of offshore export cable circuits	4	3	3
Export cable voltage (kV)	132	Up to 400	
Indicative external cable diameter (mm)	310		
Offshore cable corridor length (km)	57		
Offshore export cable length (km)	250.8		
Minimum spacing between offshore export cable circuits (m)	50		
Average Burial Depth (m)	1.2		
Width of trench by installation per m	1		
Spoil volume (m^3)	300,960		
Total seabed disturbed (km^2)	0.25		
Maximum length of surface laid cable (km)	25.1km (10 % of cable length)		

5.6.3.8.3 Cable protection

60. Where burial is not possible, e.g., at crossings or due to hard geology, cables would be surface laid with cable protection installed on top.

61. There is also likely to be a requirement for a cable protection to be installed around the array and export cables as they transition from the seabed to enter the WTG or OSP, via internal or external J-tubes or I-tubes (hollow tubes hung from the foundation that are in the shape of an "I" or "J"). There will likely be a proprietary Cable Protection System (CPS) installed around the cable itself whilst on the back deck of the vessel and before cable pull in. Additionally, there is a possibility of retrospectively installed secondary cable protection, such as rock placement or mattresses. The exact amount of cable protection required on each cable end will depend on the burial depths achieved by the export or array cable installation and assessment of the scour and movement that could occur during the operating life of the Project.

62. The exact form of cable protection used will depend upon local ground conditions, hydrodynamic processes and the selected cable protection contractor. However, the final choice may include one or more of the following: concrete 'mattresses'; rock placement; geotextile bags filled with stone, rock or gravel; polyethylene or steel pipe half shells, or sheathes; and bags of grout, concrete, or another substance that cures hard over time.

63. Mattresses are formed by interweaving a number of concrete blocks with rope and wire. They are lowered to the seabed on a frame. Once positioning over

the cable has been confirmed, the frame release mechanism is triggered, and the mattress is deployed. This single mattress placement will be repeated over the length of cable which is either unburied or has not achieved target depth. Mattresses provide protection from direct anchor strikes but are less capable of dealing with anchor drag. Should this protection method be used for crossings, a mattress separation layer may first be laid on the seabed.

64. If rock placement, or filled bags are used to protect cables, they are typically used to construct a berm on the seabed on top of the cable. The rock placement method of cable protection involves placing rocks of different grade sizes from a fall pipe vessel over the cable. Initially smaller stones are placed over the cable as a covering layer. This provides protection from any impact from larger grade size rocks, which are then placed on top. Rock bags are placed via a crane and deployed to the seabed in the correct position.

65. Half shells sections, made of metal or plastic, are bolted together forming a circular protection barrier around the cable. Additionally, rock may be placed on top to provide protection from anchors or fishing gear.

66. Where appropriate, cable clips (also known as cable anchors, or anchor clamps) may also be utilised to secure cables to the seabed. Table 5.14 shows the cable protection parameters.

Plate 5.9 Indicative cable clip (source Reda *et al,* 2021)

67. The parameters outlined in Table 5.14 provide the design envelope for the range of predicted surface laid cable protection.

Table 5.14 Cables protection parameters

Parameter	Value
Array/interconnector cables	
Maximum length of array/interconnector cable protection (m)	45,600
Width of cable protection on seabed [m]	6.0
Height of cable protection [m]	1.4
Area of cable protection (m^2)	273,600
Volume of cable protection [m^3]	383,040

Parameter	Value
Array/interconnector cables	
Export cables	
Maximum length of export cable protection (m)	25,080
Width of cable protection on seabed [m]	6
Height of cable protection [m]	1.4
Area of cable protection (m^2)	150,480
Volume of cable protection [m^3]	210,672

5.6.3.9 *Navigational markers*

68. The wind farm would be designed and constructed to satisfy the requirements of the Civil Aviation Authority (CAA) and the Trinity House Lighthouse Service (THLS) in respect of marking, lighting and fog-horn specifications. CAA guidelines as outlined in "CAA Policy and Guidelines on Wind Turbines" (February, 2016) would be adhered to. THLS recommendations would be followed as described in "Provision and Maintenance of Local Aids to Navigation Marking Offshore Renewable Energy Installations" and "the International Association of Marine Aids to Navigation and Lighthouse Authorities (IALA) Recommendation 0-139 on the Marking of Man-Made Offshore Structures", (IALA 2013).

69. The colour scheme for nacelles, blades and towers is typically RAL 7035 (light grey). Foundation steelwork is generally in RAL 1023 (traffic light yellow) up to the Highest Astronomical Tide (HAT) +15m or to Aids to Navigations, whichever is the highest.

70. Lighting requirements would follow the MCA (2021) guidance, Offshore Renewable Energy Installations: Requirements, Guidance and Operational Considerations for Search and Rescue and Emergency Response. This will ensure that adequate consideration with regard to lighting of offshore structures is given for Search and Rescue and Emergency Response. For the purposes of assessment, the following assumptions have been made with regards to lighting of North Falls:

- Aviation light
    - Only on specific structures, usually the perimeter, mounted on the top of the nacelles.
    - Off during the day.
    - Red, up to 2,000 Candela (Cd) light displayed at night only
    - Dimmable to 200 Cd when visibility is greater than 5 km at night
    - Synchronised flashing Morse "W"
    - A reduced intensity at and below the horizontal.
    - 360° visibility
    - Compatible with Night Vision Imaging Systems (NVIS)
    - UPS: 8 hours required to maintain all aviation warning lights

- Helihoist light:
    - Low intensity green 200 Cd light.
    - Off, unless the turbine is being prepared for helicopter approach.

5.6.4 Offshore construction methods

5.6.4.1 *Seabed preparation*

5.6.4.1.1 Pre-construction surveys

71. A pre-construction survey would be undertaken in advance of cable and foundation installation works. The results of this survey would be used to plan micrositing, where appropriate.

5.6.4.1.2 UXO clearance

72. The pre-construction surveys will also be analysed to identify unexploded ordnance which is required to be cleared prior to construction. For the purposes of assessment, an estimated 15 clearance operations are predicted (12 in the array areas and 3 in the offshore cable corridor). The maximum net explosive quantity of UXO in this region is predicted to be 698kg.

73. The UXO clearance procedure would be subject to additional marine licencing, to be progressed once the area in which UXO clearance activities are proposed and type of UXO are known.

5.6.4.1.3 Boulder clearance

74. Pre-construction surveys will identify any requirement for boulder clearance. An estimated 25 boulders in the array areas and 15 boulders in the offshore cable corridor, of up to 5m in diameter has been included in the assessments. Boulders would be relocated within the offshore project area, outside the foundation locations or route of the cable installation.

5.6.4.1.4 Pre-lay grapnel run

75. Before cable-laying operations commence, it would be necessary to ensure that the route is free from obstructions such as discarded trawling gear or abandoned cables identified as part of the pre-construction survey. A survey vessel would be used to clear all such identified debris, in a ‘pre-lay grapnel run’.

76. The maximum width of seabed disturbance along the pre-grapnel run would be 12m.

5.6.4.1.5 Sandwave levelling

77. Mobile sand waves could result in exposure and scouring of the cable or the cable being held in suspension over time. To prevent this, sandwave levelling may be undertaken to enable the cables to be buried into stable sediment beneath the sandwaves. In addition, some foundation options, in-particular GBS would require a level seabed prior to installation.

78. Sandwave levelling in the array areas may be required for the 228km length of array/interconnector cables, resulting in an area of temporary disturbance of up to 5.47km^2 based on a disturbance width of 24m.

79. Sandwave levelling in the offshore cable corridor may be required for the 250.8km length of export cables, resulting in an area of temporary disturbance of up to 6.02km^2 based on a disturbance width of 24m.

80. A maximum seabed preparation diameter of 70m for each WTG foundation (based on the GBS option), results in an area of temporary disturbance of 277,088.5m^2, based on the maximum of 72 WTG.

81. A maximum seabed preparation diameter of 65m for each OSP foundation (based on the GBS option), results in an area of temporary disturbance of 6,637m^2, based on the maximum of two OSPs.

82. A conservative average clearance depth of 5m is assumed, providing the following worst case volume of sediment arising from sandwave levelling and requiring disposal within the order limits.

83. Sediment disposal from seabed preparation is discussed in Section 5.6.10.

Table 5.15 Sandwave levelling volumes

Sandwave levelling volume	m^3
In the offshore cable corridor from export cable installation	30,096,000
In the array areas from array/interconnector cable installation	27,360,000
In the array areas from WTG foundation installation	1,385,442
In the array areas from OSP foundation installation	33,183

5.6.5 Foundation installation

5.6.5.1 *Pile driving*

84. The installation of piled foundations would typically consist of the following key stages:

- Prepare seabed (if necessary) prior to installation (Section 5.6.4.1);
- Delivery of monopiles or jackets to site via barge or by installation vessel. It may also be possible to tow floated piles to site using tugs;
- Mobilisation of jack-up rig with heavy craneage at installation location. It may also be necessary to mobilise a support vessel;
- Pile upended by crane to vertical position;
- Pile lowered to seabed;
- Locating of driving hammer on top of pile using craneage, and pile driven to required depth. Where ground conditions are difficult, it may also be necessary to carry out drilling (Section 5.6.5.2) using drilling equipment operated from the installation vessel before completing the driving; and
- Installation of scour protection as appropriate.

85. A drivability assessment will be conducted post-consent when further information is available regarding the ground conditions to determine the required piling requirements (e.g., hammer energy, blow rate). At this stage it is estimated that the maximum hammer energy used for pile installation would be 3,000kJ for pin piles and 6,000kJ for monopiles.

86. A soft start (gradual ramping up of hammer energy over consecutive blows) procedure, starting with a hammer energy of approximately 15% of the maximum energy for 10 minutes and then ramping up for a further 20 minutes for the 3000kJ hammer or a further 2 hours for 6000kJ.

87. During the soft start, approximately 10 hammer blows per minute will be used and during ramp up this will increase to 20 blows per minute. Once the ramp up procedure is complete hammer blows would be a maximum of 34 per minute.

88. The maximum predicted time for installation of a monopile is 7.5 hours. For a pin pile the total piling duration would be 3.5 hours per pile and with up to 4 piles per jacket, the total piling duration would be 14 hours (not including breaks in between to move and set up the next pile).

89. There could be two piling operations occurring simultaneously. Within a 24 hour period, two monopiles could be installed or four pin-piles.

90. An assessment of the underwater noise levels that could be generated by the Project is provided in Appendix 12.2 Underwater noise Modelling (Volume III).

5.6.5.2 *Drill arisings*

91. As outlined above, piles may be installed by a combination of drilling and driving.

92. Various drilling methodologies are possible, but drills are typically lifted by crane into a part-installed pile, ride inside the pile during drilling, and are removed in the event driving recommences. Drills may bore out to a diameter equal to the internal diameter of the pile, or they may be capable of expanding their cutting disk below the tip of the pile and boring out to the piles maximum outer diameter or greater (under-reaming). Drilling systems are available in sizes ranging from those required for small jacket pin piles, to large diameter concrete monopiles. Water is continuously pumped into the drill area and any drill arisings generated are flushed out and allowed to disperse naturally at the sea surface.

93. It is estimated up to 10% of the WTG locations and 50% of the OSP locations could need drilling. The maximum drill arisings would be 48,821m^3 based on the values provided in Table 5.4 and Table 5.10.

94. Sediment disposal for drill arisings is discussed in Section 5.6.10.

5.6.5.3 *Gravity base*

95. The installation method of GBS is dependent on design and fabrication methods and will be refined following the completion of post-consent commercial and technical discussions. The overall installation methodology would typically be as follows:

- Prepare seabed (if necessary) prior to installation (Section 5.6.4.1);
- GBS transported to site via barge or floated to site, hauled by tugs;
- Mobilise heavy lift floating crane (if foundation is non-buoyant solution);
- Lift foundation from barge and lower to prepared area of seabed, or adjust buoyancy of floating foundation and sink to prepared area of seabed;
- Install ballast as necessary; and
- Installation of scour protection as appropriate.

96. Ballast works would be undertaken by a trailer suction hopper dredger. The scour protection works would typically be installed by a dynamic positioning rock dumping vessel equipped with a fall pipe. The scour materials would be placed in one or multiple layers.

5.6.5.4 *Suction caisson*

97. Suction caissons would be used for jacket installation only. The installation methodology for suction caissons would typically be as follows:

- Prepare seabed (if necessary) prior to installation (Section 5.6.4.1);
- If suction caisson foundations are used these would be most likely towed to site by tugs as they are designed to be buoyant. The caisson skirt and shaft are generally delivered and installed as a single part;
- Suction caisson foundation is ballasted and lowered to seabed;
- Initial penetration occurs under foundation self-weight;
- Pumps are attached to caisson and water evacuated. Typically, there are a number of chambers within the caisson in order to implement a controlled installation and to control levels. Sometimes water jetting is used at the tip of the skirt to facilitate penetration;
- Install backfill as necessary;
- Installation of scour protection as appropriate.

5.6.6 Topside installation methods

5.6.6.1 *Tower and rotor installation*

98. The nacelle and wind turbine blades would either be transported to site and installed by the installation vessel or transported on a barge where they would be lifted off and installed by crane on a separate installation vessel. The installation of the wind turbines would typically involve multiple lifting operations, with multiple tower sections erected, followed by the nacelle with pre-assembled hub, and then the blades.

99. Traditional installation methods consist of tower segments lifted in place and bolted together, hub and nacelle conjoined in case of single blade installation.

100. Although not current practice, it is possible that wind turbines could be fully assembled and commissioned onshore and transported to site as a single unit installation.

5.6.6.2 *Substation platform*

101. The installation of the OSP foundations would be as described in Section 5.6.5. The topsides would be transported to the array area on a barge and lifted onto the platform via a crane on the vessel.

Plate 5.10 Indicative OSP topside installation (source: EnergyFacts, 2020)

5.6.7 Cable burial methods

102. Both array and export cables will be buried below the seabed wherever possible. The installation method and target burial depth will be defined post consent based on a cable burial risk assessment considering ground conditions. It is anticipated that the offshore cables will be installed via ploughing, jetting, trenching, or a combination of these techniques, depending on ground conditions along the specific cable route. Other installation methods could also be considered.

103. The parameters outlined in Section 5.6.3.8 provide the design envelope for the range of predicted installation methods.

104. The rate of the burial progress will depend on a number of factors (e.g., seabed conditions), however an indicative installation rate of approximately 150-450 m/h is expected.

5.6.7.1 *Ploughing*

105. This method involves a blade, which cuts through the seabed and the cable is laid behind. Ploughs are generally pulled directly by a surface vessel or, they can be mounted onto a self-propelled tracked vehicle which runs along the seabed. Cable ploughs are usually deployed in simultaneous ‘lay and trench’ mode although it is possible to use the plough to cut a trench for the cable to be installed at a later date provided the ground conditions are suitable. When installing the cable in simultaneous lay and trench operation the plough may use cable depressors to push the cable into position at the base of the cut trench; as the plough proceeds the trench is backfilled to provide immediate burial.

106. Ploughs can be used in seabed geology ranging from very soft mud through to firm clays but, in general, ploughs are not suited to harder substrates such as

boulder clay. Some ploughs are fitted with water jet assist options and/or hydraulic chain cutters to work through patches of harder substrates.

5.6.7.2 *Jetting*

107. This method involves directing water jets towards the seabed to fluidise and displace the seabed sediment. This forms a typically rectangular trench into which the cable generally settles under its own weight. The water jets are usually deployed on jetting arms beneath a remotely operated vehicle (ROV) system that can be free-swimming or based on passive skids or active tracks. There are also towed jetting skids available for the installation of cables. During the formation of the trench the displaced sediment is forced into suspension and settles out at a rate determined by the sediment particle size, density and ambient flow conditions. The jetting process is not intended to displace sediment to an extent that it is totally removed out of the trench; moreover, it requires that the fluidised sediment is available to fall back into the trench for immediate burial through settling. It is only the finer fractions of sediments that are likely to be held in suspension long enough to become prone to dispersal away from the trench as a plume. A key benefit of a jetting tool is that it can operate close to structures and it is also possible to use jetting tools for remedial burial if required. Typically, there are two methods of water jetting available: 'Seabed Fluidisation' and 'Forward Jetting a Trench'.

108. Seabed Fluidisation involves first laying the cable on the seabed and afterwards positioning a jetting sledge above the cable. Jets on the sledge flush water beneath the cable fluidising the soil whereby the cable, by its own weight, sinks to the depth set by the operator.

109. Forward Jetting a Trench uses water jets to jet out a trench ahead of cable lay. The cable can typically be laid into the trench behind the jetting lance.

5.6.7.3 *Trenching*

110. Trenching involves the excavation of a trench whilst temporarily placing the excavated sediment adjacent to the trench. The cable is then laid, and the displaced sediment used to back-fill the trench, covering the cable. This is most commonly used where the cable must be installed through an area of rock or seabed composed of a more resistant material. Trenching is a difficult, time-consuming and expensive method to use compared to other methods and therefore unlikely to be the preferred option for the majority of the cable corridor.

5.6.8 Connection of cables to WTGs and OSPs

111. The connection of cable to WTGs and OSPs would be done by the support of remotely operated vehicles (ROVs). The cable will be pulled into the WTG or OSP via a J-tube (or alternative cable entry system), and later connected to the WTG or OSP. A typical methodology for installing the cable into a J-tube (shown on Plate 5.1 and Plate 5.4) is as follows, although alternative cable entry details and installation methods are being considered:

- A cable barge or a specialist cable installation vessel would be mobilised to the site. The cables would be supplied either on cable reels or as a continuous length;
- The vessel would transit to site and take up station adjacent to a wind turbine structure and either holds station on dynamic positioning (DP) or sets out a mooring pattern using anchors. A cable end would be floated off from the

cable reel on the vessel towards the wind turbine structure and connected to a pre-installed messenger wire in the J-tube. The messenger wire would then allow the cable to be pulled up the J-tube;

- The cable would be pulled up the J–tube in a controlled manner with careful monitoring. When the cable reaches the cable temporary hang-off (at a later date a cable jointer would terminate the cable and install the permanent hang-off), the pulling operation ceases and the cable joint is made. The cable would be laid away from the J-tube on the first wind turbine towards the J-tube on the second wind turbine.
- When the cable installation vessel nears the J-tube on the second wind turbine structure, the cable end would be taken from the reel, ready for pulling up the J-tube; and
- The cable end would then be attached to the messenger wire from the bell mouth of the second J-tube. A tow wire would then be taken from the cable installation vessel and connected to the messenger line at the top of the J–tube and the pulling operation is repeated in the same manner as was employed at the first J-tube.

5.6.9 Jointing of offshore cables

112. Each section of cable is laid from the cable lay vessel (Plate 5.9) either from a static coil or a revolving turn carousel, turntable or drum (Plate 5.10) depending upon the characteristics of the cable. The cable is led via a cable pick-up arrangement and an associated cable track way through linear cable engines and is led overboard through a cable chute/stinger usually mounted at the stern of the vessel. For smaller array cable sizes, it is possible to use barges to lay the cable and these are generally at multiple short lengths. These sections must then be joined.

Plate 5.11 Indicative cable installation vessel (source: Van Oord, undated)

Plate 5.12 Example offshore cable drum (image courtesy of RWE Renewables)

5.6.10 Sediment disposal

113. If seabed preparation or drilling is required these methods would generate some spoil material that would require disposal. It is proposed the spoil will be disposed of within the offshore project area, with the spoil subsequently winnowed away by the natural tide and wave driven processes (see Chapter 8 Marine Geology, Oceanography and Physical Processes, Volume I).

5.6.11 Vessel and helicopter requirements during construction

5.6.11.1 *Vessel numbers and movements*

114. The number of each type of vessels required during the construction phase and the number of round trips between port and site (defined as a 'vessel movements') are summarised in Table 5.16.

115. The total number of vessels operating onsite simultaneously at the peak of the offshore construction activity is assumed to be 35.

Table 5.16 Construction vessel numbers and movements

Vessel type	Number of vessels	Number of movements
Foundation installation: • Scour Layer Vessels • Gravity Base Foundation Vessels • Jack-up installation vessels (JUVs) • Support vessels • Transport vessels • Crew transfer vessels (CTVs)	38	1,147
WTG and OSP topside installation: • Transition piece installation vessels • WTG & OSP installation vessels • Support vessels • Transport vessels • CTVs • Commissioning vessels	39	948
Array cable installation vessels (includes support, cable protection and anchor handling vessels)	12	325
Export cable installation vessels (including at landfall) (includes support, cable protection and anchor handling vessels)	12	670

5.6.11.2 *Helicopter movements*

116. There may be a requirement for helicopters to travel to and from the North Falls offshore project area to assist with construction activities. It is estimated that approximately 100 helicopter round trips may be required during the offshore construction period.

5.6.11.3 *Anchoring and jack-up*

117. Where they are used, jack-up barges (Plate 5.13) and anchored vessels will have a seabed footprint.

118. There would be six jack up locations for each WTG and OSP on average during construction. Each jack up leg could have a footprint of up to 275m^2 and it is assumed a jack up barge could have six legs, resulting in a total footprint of 732,600m^2 for 72 WTG and two OSPs.

119. Anchoring may also be required during foundation installation, with an average of five anchoring events per foundation (at up to 72 WTG and two OSPs).

Assuming an anchor width of 4.85m and drag of 24m (footprint of 116.39m^2), and eight anchors per vessel, the total footprint would be 344,529m^2.

120. Anchoring may also be required during installation of the export and array cables. It is estimated there would be 264 anchoring events during array and interconnector cable installation and 545 during export cable installation. Assuming an anchor width of 4.85m and drag of 12.51m (footprint of 60.69m^2), and nine anchors per vessel, the total footprint would be 441,902m^2 (144,076.8m^2 for array cables and 297,825.5m^2 for export cables).

Plate 5.13 Example jack-up barge (image courtesy of RWE Renewables)

5.6.11.4 *Safety zones*

121. During construction and periods of major maintenance, NFOW would seek to agree appropriate safety zones around any potentially hazardous works.

122. Application for safety zones will be made post consent under 'The Electricity (Offshore Generating Stations) (Safety Zones) (Applications Procedures and Control of Access) Regulations 2007' (S.I. No 2007/1948).

123. The Applicant will apply for safety zones of 500m around any structure where construction and major maintenance is ongoing (i.e., where there may be sensitive vessel operations underway). In addition, pre-commissioning safety zones of 50m in radius will be applied for around structures up until the point of final commissioning of the Project.

124. Advisory safe passing distances may also be promulgated around any sensitive operations, where a safety zone does not apply (e.g., cable installation).

125. Safety zones are discussed further in Chapter 15 Shipping and Navigation (Volume I).

5.6.12 Oils, fluids and effluents

126. Oils in the wind turbines shall be biodegradable where possible. All wind turbines will have provision to retain all spilt fluids within nacelle/tower. The volume of oil and fluids will vary depending on wind turbine design, i.e., conventional (geared) design or gearless (direct drive), whether one or two or more rotor bearings are used in the design and the amount of redundancy designed into the system.

127. All chemicals used will be certified to the relevant standard. The following indicative substances are typical in offshore wind farm infrastructure:

- Grease;
- Synthetic oil / hydraulic oil;
- Nitrogen;
- Water / glycerol;
- Mineral, natural or synthetic transformer oil e.g., mineral oil, silicone or midel; and
- SF6 gas or equivalent alternative.

5.6.13 Offshore construction programme

128. The final design (e.g., number of turbines, platform, cables, etc.) and supply chain will affect the construction programme, as well as weather conditions during construction.

129. Indicative programmes are provided below in Table 5.17. Offshore working hours during construction are anticipated to be 24/7.

Table 5.17 Indicative offshore construction programme

	Year 1				Year 2				Year 3				Year 4			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Substation installation and commissioning	N/A (onshore construction only)															
Export cable installation																
Foundation installation																
Array cable installation																
Wind turbine installation																
First generation																
Wind turbine and foundation commissioning																

5.6.14 Offshore operation and maintenance

5.6.14.1 *Operation*

130. The operation and control of the wind farm would be managed by a Supervisory Control and Data Acquisition (SCADA) system, connecting each turbine to the onshore control room. The SCADA system would enable the remote control of individual turbines, the wind farm in general, as well as remote interrogation, information transfer, storage and the shutdown or restart of any wind turbine if required.

5.6.14.2 *Maintenance*

131. All offshore infrastructure including wind turbines, foundations, cables and offshore substations would be monitored and maintained during the operation and maintenance (O&M) period in order to maximise operational efficiency and safety for other sea users.

132. Typical maintenance activities would include:

- General scheduled service of wind farm components (e.g., painting and cleaning of WTG structures, servicing of electrical equipment);
- Unscheduled repair and maintenance of wind farm components (e.g., major WTG and electrical equipment components and/or minor repairs/replacements such as ladders, J tubes and anodes)
- Oil sampling / change;
- UPS (uninterruptible power supply) battery change;
- Service and inspections of wind turbine safety equipment, nacelle crane, service lift, high voltage system, blades;
- Cable burial inspection;
- Cable repair and replacement;
- Foundation inspection and repair; and
- Cable crossing inspection and repair.

5.6.14.2.1 Cable repairs

133. During the life of the Project, there should be no need for scheduled repair or replacement of the subsea cables, however, reactive (unscheduled) repairs and periodic inspection may be required.

134. An estimated four repairs of the export cables and five repairs of the array/interconnector cables, approximately over the Project life is included in the EIA. It is assumed 600m would be removed and replaced in the event of a repair operation.

135. In most cases a failure would be repaired by taking out the damaged part of the cable, cutting the cable, inserting a joint, bringing a new segment of cable and jointing the new segment with the old cable.

136. The cable would be unburied using jetting (or removal of mattress/rock protection) and then once the repair is done the opposite (reinstalling the mattress, rock dumping, jetting or other methods of cable burial or protection).

5.6.14.2.2 Cable reburial

137. Periodic surveys would be required to ensure the cables remain buried and if they do become exposed, re-burial works would be undertaken. An estimated 5km of the array cable and 5km of the export cable requiring reburial over the Project life is included in the EIA.

5.6.14.2.3 WTG maintenance

138. The wind farm would be maintained from shore using a number of O&M vessels (e.g., crew transfer vessels) possibly supported by helicopters.

139. Although it is not anticipated that large components (e.g., wind turbine blades or substation transformers) would frequently require replacement during the operational phase, the failure of one of these components is possible. Should this be required, a jack-up vessel may need to operate continuously for significant periods to carry out these major maintenance activities.

5.6.15 Vessel and helicopter requirements during O&M

5.6.15.1 *Vessel types and movements*

140. The number of each type of vessels required during the O&M phase and the annual number of round trips between port and site (defined as a 'vessel movements') are summarised in Table 5.18.

141. The total number of annual vessel movements is 1,587.

Table 5.18 O&M vessel numbers and movements

Vessel type	Number of vessels	Annual number of movements
Jack up vessels	2	7
Service operations vessels	2	52
Small O&M vessels (e.g., crew transfer vessels)	6	1460
Lift vessels	2	7
Cable maintenance vessels	2	1
Auxiliary vessels	8	60

5.6.15.2 *Helicopter movements*

142. There may be a requirement for helicopters to travel to and from the North Falls offshore project area to assist with O&M activities. It is estimated that approximately 100 helicopter round trips may be required during the O&M period.

5.6.15.3 *Anchoring and jack-up*

143. It has been assumed that a maximum of 180 jack-up events could be required per year. With a jack-up footprint of $275m^2$ per leg and 6 legs, this represents an annual footprint of $0.3km^2$.

144. Anchoring may be required during any required repairs of the export and array cables (Section 5.6.14.2.1). As described in Section 5.6.11.3, anchoring would have an estimated footprint of $60.69m^2$ per anchor with up to nine anchors per

vessel. It is therefore estimated the anchor footprint during cable repairs could be 546m^2 per repair.

5.6.15.4 *Safety zones*

145. During O&M activities NFOW would seek to agree appropriate safety zones around wind turbines if required during major maintenance works. Safety zones are discussed in Chapter 15 Shipping and Navigation (Volume I).

5.6.15.5 *O&M port*

146. An O&M facility would be required, however this does not form part of the DCO application. The facility would be located in a service port (yet to be chosen). An office, storage or warehouse facility and quayside loading area would be needed.

5.6.16 Offshore decommissioning

147. The scope of the decommissioning works would be determined by the relevant legislation and guidance at the time of decommissioning and would most likely involve the accessible installed components.

148. Offshore, this is likely to include removal of all of the wind turbine components part of the foundations (those above seabed level). Cables, cable protection and scour protection would likely be left in situ. The anticipated techniques for the various foundation types are as described below. The timescale for decommissioning works is estimated to be approximately 3 years.

149. The number of vessels and helicopters required for decommissioning are expected to be similar to construction (see Section 5.6.11.2).

150. As an alternative to decommissioning, the owners may wish to consider re-powering the wind farm. Should the owners choose to pursue this option, this is likely to be subject to a new application for consent.

5.6.16.1 *Monopile foundations*

151. The overall removal methodology for steel monopile foundations would typically be as follows:

- Removal of turbine, mast, switchgear and ancillaries, and cutting of cables (leaving buried array cables in situ);
- Mobilisation of service vessel;
- Local jetting and/or suction around base of monopile to a depth of approximately 1-2m;
- Deployment of underwater remote abrasive cutting equipment from service vessel;
- Mobilisation of heavy lift DP vessel or jack-up rig and attachment of crane slings to top of monopile and TP;
- Abrasive cutting of monopile at a depth of approximately 1-2m below the seabed;
- Lifting of combined monopile/TP by crane on DP vessel or jack-up rig onto barge;
- Transportation of monopile/TP to port and dry dock for dismantling and reuse where possible, or recycling where practicable.

152. It would not be intended to reinstate the local excavations remaining at the monopile locations as it is anticipated that this would refill naturally over time.

5.6.16.2 *Pin-pile jacket foundation decommissioning*

153. The overall removal methodology for pin pile foundations would typically be as follows:

- Removal of turbine, mast, switchgear and ancillaries, and cutting of cables (leaving buried array cables in-situ);
- Local jetting and/or suction around legs of jacket to a depth of approximately 1-2m;
- Deployment of underwater remote abrasive cutting equipment from service vessel;
- Mobilisation of heavy lift DP vessel or jack-up rig and attachment of crane slings to jacket;
- Abrasive cutting of pile legs at a depth of approximately 1-2m below the seabed;
- Lifting of jacket by crane on DP vessel or jack-up rig onto barge; and
- Transportation of jacket to port and dry dock for dismantling and reuse where possible, or recycling where practicable.

154. It would not be intended to reinstate the local excavations remaining at the pile leg locations as it is anticipated that this would refill naturally over time.

5.6.16.3 *Gravity base structures*

155. The overall removal methodology for gravity base structures would typically be as follows:

- Removal of turbine, mast, switchgear and ancillaries, and cutting of cables (leaving buried array cables in-situ);
- Mobilisation of heavy lift DP vessel or fleet of tugs (dependent on whether foundation design is buoyant or requires heavy lift);
- Removal of marine growth and sediment from base and jetting under base plate to remove adhesive effects of grout (if present) or cohesive bearing material. If a deep skirt has been used, the skirt may require cutting;
- It may also be necessary to locally remove scour protection via dredging;
- For buoyant design: controlled de-ballasting of foundation using remote pumping equipment and/or installation of buoyancy aids. Foundation will become buoyant on de-ballasting;
- For design requiring heavy lift: lifting of foundation from seabed onto barge (as per installation, a bespoke transportation barge may be required dependent on the design); and
- Transportation of foundation to port and dry dock (via towing or on barge dependent on foundation type) for deconstruction and reuse where possible, or recycling where practicable.

5.6.16.4 *Suction caisson foundations*

156. The overall removal methodology for suction caisson foundations would typically be as follows:

- Removal of turbine, mast, switchgear and ancillaries, and cutting of cables (leaving buried array cables in-situ);
- Mobilisation of service vessel with pumping equipment and ROV, and mobilisation of tugs. It may also be necessary to mobilise a DP vessel with craneage to facilitate with the refloating and subsequent manipulation of the foundation;
- Removal of sediment and marine growth from suction caisson lid, and jetting of pump connections on lid. It may also be necessary to locally remove scour protection via dredging;
- De-ballasting or adding of buoyancy aids to foundation as required by design;
- Connection of pumping equipment to suction caisson valves;
- Controlled pumping of water into caisson chambers. The caisson will rise from its installed position to the surface as the internal pressure overcomes the side wall friction. Some manipulation from craneage on a DP vessel may also be required; and
- Towing of foundation to port and dry dock for dismantling and reuse where possible, or recycling where practicable.

5.6.16.5 *Removal of scour protection*

157. Where scour protection materials have been used, it is likely that they would be left in place. There would be some disturbance of the scour protection materials during the removal of the foundations but they would simply fall to the seabed and flatten over time.

5.6.16.6 *Removal of cabling*

158. General UK practice will be followed, i.e., buried cables would be cut at the ends and left in-situ.

5.6.16.7 *Safety zones*

159. During decommissioning NFOW would seek to agree appropriate safety zones around any potentially hazardous works. Safety zones are discussed in Chapter 15 Shipping and Navigation (Volume I).

5.6.17 Offshore embedded mitigation

160. The following key mitigation commitments have been made in designing the offshore components of the Project:
    - An early decision was made to refine the Project boundary, discussed further in Chapter 4 Site Selection and Assessment of Alternatives (Volume I). The following were removed:
        - Overlap with an aggregate licensed area in proximity to the northern array;
        - An area within the Kentish Knock East MCZ which overlapped with an existing interconnector cable, to avoid cable crossings in the MCZ;
        - Areas of the northern array area which overlapped International Maritime Organisation designated vessel routing measure;

- An area to the north-east of the northern array area, to avoid the export cables of Greater Gabbard and Galloper offshore wind farms.

- The offshore cable corridor was designed in consultation with key nature conservation and shipping consultees to minimise impacts on these receptors (discussed further in Chapter 4 Site Selection and Assessment of Alternatives, Volume I); and
- There will be a soft start and ramp up of pile driving.

5.7 Landfall

161. 'Landfall' refers to the area between Mean Low Water Springs (MLWS) and location at which the offshore export cables are brought ashore, and connected to the onshore export cables within transition joint bays. High Density Polyethylene (HDPE) ducts to house the cables are proposed to be installed at landfall using Horizontal Directional Drill (HDD) methodology. The offshore export cables are then pulled through the pre-installed ducts, which terminate at the transition joint bay(s), where they are jointed to the onshore export cables within the temporary landfall compound. Further details regarding landfall infrastructure and construction are set out below.

5.7.1 Landfall location

162. The export cables will be brought ashore in the landfall search area between Clacton-on-Sea and Frinton-on-Sea. The precise landfall location between these two settlements will be subject to further site selection, considering relevant consultation feedback and initial EIA and engineering survey data, in advance of the Project's DCO submission.

5.7.2 Landfall project details summary

Table 5.19 Landfall project characteristics

Feature	Parameters
Maximum number of export circuits	4
Maximum number of transition joint bays	4
Permanent land take for each transition joint bay (per bay)	4 x 15m
Landfall construction compound dimensions	100 x 200m
Proposed landfall installation method	Horizontal Directional Drilling (HDD)
Maximum number of HDDs	5
Maximum length of HDD	1,100m
Drill exit location	Subtidal exit below MHWS (up to 8m depth).
Maximum depth of HDD	20m

5.7.3 Landfall construction methods

5.7.3.1 *Horizontal directional drilling*

163. HDD involves a three-stage process (as shown in Plate 5.14) wherein:

- A small diameter pilot bore is drilled along the designated route;

- The pilot bore is enlarged by passing a larger cutter tool known as the reamer through the bore a number of times to progressively enlarge the bore to the required diameter; and
- Ducts are installed within the enlarged hole and the offshore export cable is pulled through the ducting.

164. Drilling is facilitated with the aid of a viscous fluid known as drilling fluid. It is typically a mixture of water and bentonite (an inert form of clay), and which may contain other additives which would be required depending on the nature of the drilling process used. The drilling fluid is continuously pumped to the cutting head or drill bit to facilitate the removal of cuttings, stabilise the borehole, cool the cutting head, and lubricate the passage of the duct. Drilling fluid would be recycled where practicable, with fluid pressures monitored throughout the process to minimise the potential for breakout (frac-out) of the drilling fluid. A breakout may occur if the drilling fluid escapes through natural fissures in the bedrock or other weaknesses in geology and reaches the surface. A breakout contingency plan will be prepared in advance of works, detailing the procedures to be followed in the event of breakout.

165. A small pilot hole is drilled from an onshore entry pit and advanced in stages until a predetermined distance from the seabed exit point is reached (forward reaming). This is likely to be approximately 20-50m from the seabed exit point. The pilot hole would be drilled along a predetermined path using a mud-motor or jet bit on the end of a pilot string. As the pilot hole extends through the superficial layer of ground (typically topsoil and made ground), casing (typically a metal pipe or collar around 20-50m long) may be installed in the bore to assist in maintaining the integrity of the upper ground layer. Pilot hole drilling operations continue until the exit point is approached, although at landfall the pilot hole would not break through the final section of seabed. Then the smaller pilot string is removed with the casing (if used).

166. Once the pilot hole is completed, the bore will be enlarged by passing a larger cutting tool known as a reamer. This would be achieved by passing the reamer through the bore a number of times to progressively enlarge the bore to the diameter required for duct installation. During the final reaming, the bore would progress to the final exit point on the seabed – this process is called punch-out. Typically, reaming takes place in a forward direction, from the HDD rig outward along the pilot hole and back.

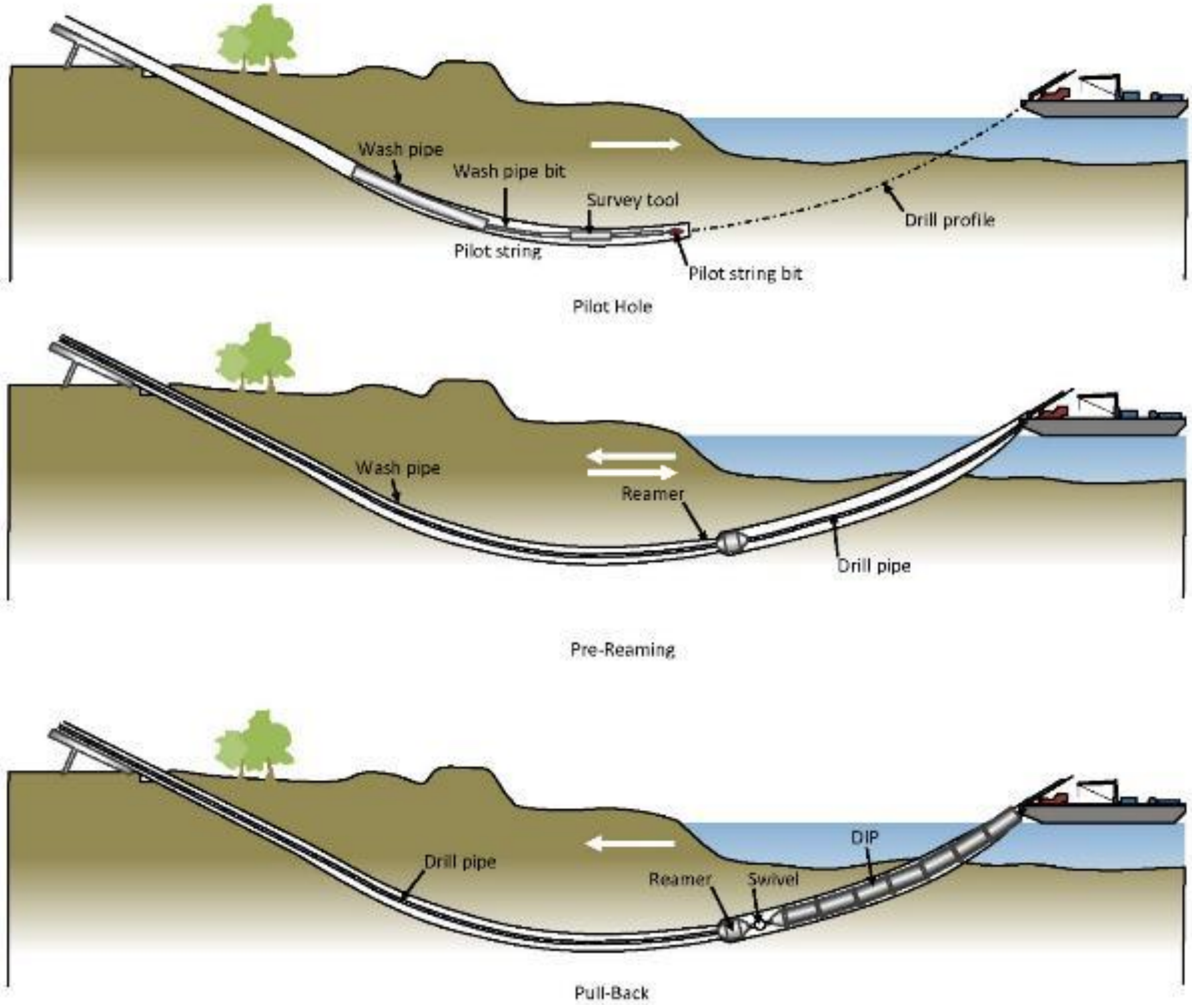

Plate 5.14 Example HDD working method at landfall

167. The ducts would be typically floated into position at the offshore exit point via barges. The ducts would then be flooded with water and pulled into the reamed drill hole from the entry pit, using a drill rig. Alternatively the ducts could be welded in sections onshore and pulled from the offshore side. Once the duct is installed, the ends would be covered or plugged until the offshore export cable is ready to be installed.

168. Following installation, the duct would be backfilled and surrounded with bentonite or a similar material for thermal resistivity purposes.

169. Installation by HDD would require a fenced landfall construction compound. A maximum 100 x 200m temporary landfall construction compound for up to four transition joint bays may be required.

170. The HDD works would progress with the following stages:

- Mobilise equipment to the selected landfall site and prepare a temporary construction base including hardstanding, temporary office cabins and bunded re-fuelling areas;
- Install a deadman anchor, typically of heavy duty sheet pile anchor wall, to prevent the HDD rig moving forward (absorb thrust during drilling);

- Position the HDD rig behind the deadman wall close to entry pit and drill a pilot hole;
- Enlarge the pilot hole by reaming;
- 'Punch-out' of the seabed during the final reaming to complete the drill;
- Install the duct into the enlarged hole;
- If required, cover or plug the duct until the offshore export cable is ready to be pulled into the duct; and
- Removal of construction equipment and partial reinstatement of the site to its previous condition. Site is not fully reinstated as the site will be used again during the cable installation process (see below).

Plate 5.15 Example of an HDD drill rig at landfall – the cable duct is closest in the foreground (image courtesy of RWE Renewables)

5.7.3.2 *Cable installation*

171. Once the offshore export cable is ready to be installed into the duct at landfall, the following steps would be required:

- Upon arrival of the export cable installation vessel, the duct exit would be exposed. This may be achieved with methods such as use of a mass flow excavator (a submersible tool used to clear sediment without damaging the duct);
- The export cable installation vessel would be positioned at the HDD exit point by anchors prior to undertaking the cable pull-in operation, and the offshore export cables would be pulled ashore through the duct; and
- Following the completion of the pull-in operation (and subsequent termination and cable testing) the export cable installation vessel would commence cable lay operations for the remainder of the export cable.
- Subsequent to the cable lay operations, the cable in the transition zone between the HDD duct and full depth of the cable trench would be lowered

utilising diver-based jet lancing and dredging operations, most likely supported from a small anchored or spudded / jack-up barge.

5.7.3.3 *Cable jointing and transition joint bays*

172. The heavily armoured offshore export cables and the onshore cables are jointed within transition joint bays located at the landfall HDD construction compound. A maximum of four transition joint bays would be constructed within the HDD temporary construction compound at landfall. The exact compound location has yet to be confirmed, however, it will be located within the landfall compound search area, as shown on Figure 1.2 (Volume II). Once the cables are jointed, each transition joint bay is backfilled and the cables buried. The only visible above ground structures are the concrete link boxes (see Plate 5.14 and Plate 5.24 for link boxes before and after reinstatement).

173. The installation of each transition joint bay would involve the following:

- Mechanical excavation of the transition joint bay chamber (excavation would be slightly larger than the joint bay dimensions). Excavated material would be stored and used as backfill with any excess removed from site and suitably disposed of;
- Dewatering of excavations may be required. This would require the establishment of a pump for dewatering the excavations;
- Construction of transition joint bay chamber:
    - Each transition joint bay will be constructed of a reinforced concrete base slab to provide a clean surface for jointing of the cables;
    - After jointing is completed, the predetermined area around the cables is typically backfilled with suitable engineered material, such as Cement Bound Sand (CBS);
    - The remaining area of the transition joint bay are backfilled with suitable excavated soil.

174. The permanent below-ground footprint of each transition joint bay would be up to 4 x 15m. The depth of burial would be up to 2.5m. The ground surface would be reinstated to its original condition and use following completion of the construction works, as practicable.

Plate 5.16 Example transition joint bay including the concrete link boxes – the tops of which are the only structures that are visible above ground once reinstatement is complete (image courtesy of RWE Renewables)

5.7.4 Landfall embedded mitigation

175. The following key mitigation commitments have been made in designing the Project's landfall location and construction methodology:

- An early decision was made to minimise potential effects upon the Holland Haven Marshes Site of Special Scientific Interest (SSSI) through the following commitments:
    - HDD will be used as the preferred construction method at the landfall, minimising the potential for disturbance of surface features of the SSSI;
    - The landfall compound search area is located entirely outside the SSSI boundary; and
    - Following consultation with Natural England and the Environment Agency during the Project's Evidence Plan Process, a breakout management plan will be developed to manage the risks of HDD breakout during landfall construction. This plan will be consulted on with Natural England and the Environment Agency in advance of DCO submission.

  In addition, the following commitments have been made:

- Transition joint bays will be buried, with the land above reinstated to pre-construction ground level, with the exception of link box chambers where access will be required from ground level (via manholes). Once constructed, transition joint bays and link box chambers will be designed to have a high degree of flood resilience.
- Post-construction, the ground surface will be re-instated to its previous condition and use (as practicable).

5.8 Onshore

176. The Project's onshore infrastructure comprises the following elements:

- onshore export cables connecting the offshore export cables at landfall to the onshore substation and on to the National Grid connection point;
- the Project's onshore substation.

177. The Project may additionally require works to connect the Project to the National Grid, however at this stage in the Project design the nature of these works are unknown due to the early stage of National Grid's design of the East Anglia GREEN project substation. Further details regarding National Grid connection works are summarised in Section 5.8.4.7.

178. Further details regarding project's onshore infrastructure and construction are set out below.

5.8.1 Onshore location

179. The Project's onshore infrastructure is proposed to be located entirely within the Tendring peninsula of Essex. The location of the Project's onshore infrastructure is subject to further refinement through site selection, consideration of relevant consultation feedback and initial EIA and engineering survey data. However, at this stage the following have been identified:

- Onshore cable corridor(s), comprising at least 204m wide (up to 243m wide) broad corridors in which the onshore export cables will be located;
- Onshore substation zone, comprising an approximately 60ha zone within which the Project's onshore substation will be located.

180. The footprint of the Project's onshore infrastructure is referred to herein as the 'onshore project area', and is shown on Figure 1.2 (Volume II).

5.8.2 Onshore project details summary

181. Key onshore project characteristics are summarised in Table 5.20 below. Detailed project characteristics for each element of onshore infrastructure is described in subsequent sections.

Table 5.20 Onshore project characteristics

Feature	Worst case parameters
Electrical connection type	High Voltage Alternating Current (HVAC)
Expected grid connection location	Within East Anglia GREEN proposed substation location (see Figure 1.2, Volume II).
Maximum number of onshore circuits	Up to 4 circuits, comprising 3 power cables, 3 telecommunications cables and 1 earth cable in each circuit
Proposed cable installation method	Open cut trenching and trenchless techniques (e.g., HDD) in sensitive locations (see Appendix 5.1 Crossing Schedule (Volume III).
Proposed onshore cable route construction width	Up to 60m (open cut trenching) Up to 122m (trenchless installation (e.g., HDD))
Cable trench dimensions	1.45m (width at base) – 3.75m (width at top) x 2m (depth)
Approximate onshore export cable length	24km

Feature	Worst case parameters
Maximum depth at trenchless crossings	20m
Estimated number of cable construction compounds	Up to 7
Cable construction compound footprints	150 x 150m (cable construction compounds) 100 x 100m (small cable construction compounds) 80 x 120m (major HDD compounds) 40 x 120m (minor HDD compounds)
Maximum onshore substation platform footprint	267 x 300m
Maximum onshore substation construction compound footprint	150 x 250m
Maximum onshore substation equipment height	18m

5.8.3 Onshore export cables

182. At this stage in the Project's design, broad onshore cable corridor(s) have been identified within which the onshore export cables will be located. These corridors are up to 243m in width depending on the degree of engineering flexibility required prior to the completion of further EIA and engineering design studies and to take into account ongoing engagement with landowners and consultation feedback. Multiple corridors have been retained in certain locations along the onshore cable corridor(s) in order to maintain additional flexibility at this stage. Prior to submission of the Project's DCO application, these onshore cable corridor(s) will be refined into a single onshore cable route, within which the Project's onshore export cables construction works will take place.

183. The onshore cable corridor(s) are shown on Figure 1.2 (Volume II).

184. The parameters of the onshore export cables are provided below in Table 5.21.

Table 5.21 Onshore export cables characteristics

Feature	Parameters
Electrical connection type	High Voltage Alternating Current (HVAC)
Maximum number of onshore circuits	Up to 4 circuits, comprising up to 3 power cables, 3 telecommunications cables and 1 earth cable in each circuit
Estimated number of cable construction compounds	Up to 7
Cable construction compound footprint (m)	150 x 150m (general cable construction compounds) 100 x 100m (small cable construction compounds)
Indicative external cable diameter	200mm
Proposed onshore cable route construction width	Up to 60m (open cut trenching) Up to 82m (shallow trenchless crossings (e.g., HDD)) Up to 122m (deeper trenchless crossings (e.g., HDD))
Approximate onshore cable length	24km
Number of ducts required per circuit (where ducted) per circuit	Up to 4
Total maximum number of ducts onshore	Up to 16
Number of joint bays	80 – 192 (approximately every 500m)

Feature	Parameters
Joint bay dimensions	13 x 5m
Estimated number of link boxes	Up to 196
Number of trenches for all cables	Up to 4
Cable trench dimensions	3.75 x 2m (width x depth)
Approximate depth of trench to top of protection tile	0.85m – 1.2m
Minimum cable burial depth	0.9m
Typical minimum depth of trenchless crossings below watercourses	1.5m
Maximum depth at trenchless crossings	20m
HDD compound dimensions	80 x 120m (major HDD compounds) 40 x 120m (minor HDD compounds)
Haul road carriageway width - allowable within the cable swathe	6m
Haul road width passing places and drainage – allowable within the cable swathe	10m
Estimated distance between haul road passing places	500m

5.8.3.1 *Site establishment*

5.8.3.1.1 Construction accesses

185. New accesses from the local highway network will be constructed in advance of the construction works in that location to facilitate access to the onshore corridor(s). Road modifications could be required to facilitate the safe ingress and egress from the public highways at these locations.

186. At the current stage in the Project's design, the location of these access points are still under review, and their locations will be assessed within the Project's onshore project area within the ES.

187. All construction accesses would be removed and land reinstated following the completion of construction, unless requested to remain in situ by the relevant landowner and subject to the landowner obtaining any necessary consents.

5.8.3.1.2 Construction compounds

188. Temporary construction compounds are required to support the onshore cable installation. A maximum of seven compounds will be required, including one main construction compound. Construction compounds would also be required at landfall and the substation sites.

189. Construction compounds would be required to support the cable duct installation and cable pulling works. They would act as a hub for the onshore construction works and would house the central offices, welfare facilities, and stores as well as acting as a staging post and secure storage for equipment and component deliveries (see Plate 5.19). Construction compounds would be fenced and be supported by temporary lighting where required. Construction compounds would be established in advance of the construction works in that

location and would remain in situ for the duration of construction in any one location.

190. Where there is no existing hardstanding, construction compounds would be constructed by laying a geotextile membrane or similar directly on top of the subsoil which would have stone spread over the top. Following completion of construction, geotextile / stone would be removed and the site reinstated.

Plate 5.19 Example construction compound (image courtesy of RWE Renewables)

5.8.3.1.3 Construction drainage

191. Prior to construction, surface water drainage would be developed and implemented to minimise water within the cable trench and ensure ongoing drainage of surrounding land. Water filling the trenches would be appropriately treated to ensure no adverse effects on the local watercourses.

192. Detailed construction drainage would be developed post-consent by a specialist drainage contractor, taking into account existing land drainage. A soakaway drainage pit may be required where infiltration rate is found suitable, if no suitable outfall to a nearby by watercourse is possible.

193. Post-construction, agricultural drainage would be reinstated to include the replacement of any drains that were damaged during the construction process.

5.8.3.1.4 Topsoil strip and soil management

194. Topsoil would be stripped in advance of works in any one area of the onshore cable route in advance of construction.

195. Stripped topsoil and excavated subsoil would be stored separately within the onshore route. The area to be used for storing the topsoil would be cleared of vegetation and any waste arising from construction works (e.g., building rubble and fill materials). Topsoil would also be stripped from any land to be used for storing subsoil.

196. Effective stockpiles would be created by:

- Removing vegetation and waste materials from the area before forming stockpiles;
- Storing topsoil and subsoil layers separately;
- Locating stockpiles away from trees, hedgerows, drains, watercourses or excavations;
- Managing the site so that soil storage periods are kept as short as possible;
- Stockpiling soils in the driest condition possible;
- Using tracked equipment wherever possible to reduce compaction; and
- Protecting stockpiles from erosion by seeding or covering them.

197. Soil would be managed in line with MAFF (2000) Good Practice Guide for Handling Soils and Defra (2009) Construction Code of Practice for the Sustainable Use of Soils on Construction Sites.

198. Soil management is discussed further in Chapter 22 Land Use and Agriculture (Volume I).

5.8.3.1.5 Haul road

199. The haul road would provide safe access for construction vehicles along the onshore cable corridor(s), between construction compounds and the work fronts. This would minimise the amount of vehicle movements between work areas on the existing road network. The haul road traffic surface would typically be 6m wide (and up to 10m wide at passing bay locations, located at approximately 500m intervals) with drainage and verges either side (see Plate 5.17). As a worst-case it is assumed to be required along the full length of the onshore cable corridor(s). Speed limits on the haul road are expected to be limited to 20 miles per hour (mph).

200. Following an initial topsoil strip, the haul road would be installed in stages as each work front progresses. It would be formed of protective matting, temporary metalled road or permeable gravel aggregate dependent on the ground conditions, vehicle requirements and any necessary protection for underground services.

201. Should the onshore cable onshore cable corridor(s) cross an open ditch or drain, and access for the haul road is required, an appropriately sized culvert may be installed within the ditch. The haul road would be installed over the top of the culvert to maintain access along the onshore cable corridor(s) either side of the ditch. The culvert would be installed in the channel bed so as to avoid upstream impoundment, and would be sized to accommodate reasonable worst-case water volumes and flows. The culverts may remain in place for the duration of the cable duct installation and subsequent cable pull.

202. At larger crossings, temporary bridges may be employed to allow continuation of the haul road. At sensitive locations, such as rail or river crossings, the haul road would effectively stop and would re-start on the opposite side.

203. When cable duct installation is completed, the haul road would be removed and the ground reinstated using stored topsoil. Some sections of the haul road may need to be retained or reinstated to maintain access for the subsequent cable pulling stage.

Plate 5.17 Example haul road (image courtesy of RWE Renewables)

5.8.3.2 *Cable duct installation*

204. The onshore export cables comprise four separate circuits, with up to three HVAC power cables per circuit. The onshore export cables would be laid underground in HDPE ducts, and would transport electrical power from landfall transition joint bay to the onshore substation.

205. The primary cable installation method would be open cut trenching, with cable ducts installed within the trench(es) and surrounded with suitably engineered soil (CBS) before backfilling with selected excavated soil. Cables would then be pulled through the pre-laid ducts at a later stage in the construction programme. Where it has not been possible for the onshore cable corridor(s) to avoid crossing constraints such as transport routes (road and rail) or watercourses, then alternative trenchless crossing methodologies will be required, such as HDD.

206. Precise construction methods would differ according to the nature of the environment through which the onshore cable corridor(s) was being constructed. Of particular importance are the underlying soils and strata, existing hydrological regimes, the terrain, existing physical constraints (such as other underground services) and environmental constraints (such as development or environmentally sensitive areas).

207. The installation of the onshore export cables is expected to take between 18 – 24 months in total. The number of teams associated with the installation of the onshore export cables is yet to be determined, as is the length of corridor to be worked on each day (see Section 5.8.5 for details of the onshore construction programme).

208. All aspects of the construction work would be in accordance with the Construction (Design and Management) Regulations 2015, as amended or replaced.

5.8.3.2.1 Open cut trenching

209. Cables ducts would be predominantly installed in up to 4 (four) open cut trenches and would be installed approximately 1.2m below ground level (bgl). Cables would typically be 200mm in diameter (the duct being larger, approximately 300mm). An indicative open cut trenching cable cross-section is provided below.

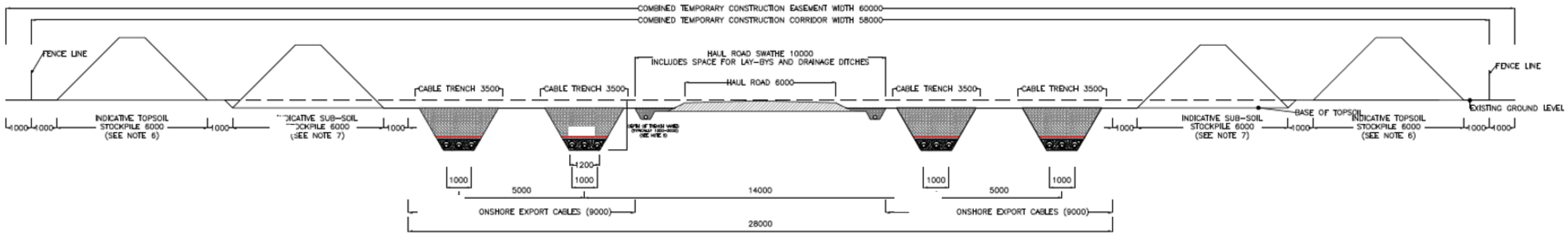

Plate 5.18 Typical construction swathe cross-section for open cut trenching

210. Each cable trench would require distributed temperature sensing (DTS) cabling to be installed next to the ducts or cables. Typically, this system comprises of a fibre optic cable within a protective sheath or duct. The DTS identifies faults in the buried cable during operation, allowing the precise location of any fault to be identified and more accurate excavation of the ground to facilitate the cable repair. Fibre optic and SCADA cables would also be installed adjacent to the onshore export cables.

211. Prior to installation, topsoil would be stripped from the section of the onshore cable corridor(s) to be worked on and stored within the working width. The cable trenches would then be excavated. The excavated subsoil would be stored separately from the topsoil, and both would be managed to minimise soil erosion. Soil management is discussed further in Section 5.8.3.1.4 below, and in Chapter 22 Land Use and Agriculture (Volume I).

Plate 5.19 Typical open cut trench (image courtesy of RWE Renewables)

212. The cable duct installation works would be a continuous activity with a ‘work front’, with installation being undertaken within one section of the onshore cable corridor(s) before moving on to the next. In any given location, once the cable ducts have been installed the trenches would be backfilled and the work front would continue moving onto the next section. This would minimise the amount of land being worked on at any one time.

213. Ducts would be buried to a minimum depth of 0.85 – 1.2m (from top of protection tiles to surface) and installed using two methods:

- Hand laying of the ducts, which is suited to short and / or complicated sections; and
- The use of a ducting trailer or trenching machine for longer uninterrupted trenching sections.

Hand laying method

214. Ducts would be palletised and manoeuvred along the easement using a telehandler (or equivalent). Operatives in the trench would lay zip ties in the base of the trench following the profile of the trench base and sides at predetermined intervals ahead of the ducts being laid. Ducts are then laid out alongside the trench prior to lifting and lowering into the trench. The ducts would then be joined together in the trench.

Ducting trailer method

215. For longer sections of ducting a ducting trailer or trenching machine may be used. This enables the ducts to be joined on the trailer platform and lowered directly into the trench as the tractor moves the trailer forward. The ducts are zip tied into the correct formation prior to leaving the working platform. The use of the duct trailer or duct machine minimises the need for personnel to work in the trench.

Plate 5.20 Example cable trenching machine (image courtesy of RWE Renewables)

Duct surround and backfill

216. Depending on the thermal resistivity of the soil and the height of the water table, it is likely that a stabilised backfill such as CBS would be required to encase the ducting. This is commonly used to ensure that the thermal conductivity of the material around the cables is of a known consistent value for the length of installation.

217. CBS has a low thermal resistance to conduct the heat produced during electricity transmission away from the high voltage cables. Additionally, as CBS tends to consist of a weak sand to cement ratio (typically 14:1), it is relatively easy to remove if maintenance or removal of ducts is required.

218. Once the ducts are encased in CBS (typically covering a depth of 100mm above the ducts to ensure the thermal resistivity requirements are met) a compaction plate would be used until the required level of compaction is achieved. Protection tiles and/or warning tapes are laid on top of the CBS. The trench would then be backfilled in stages using the subsoil stored at the side of the trench(es) and compacted using suitable compaction plant. A warning tape is laid 100mm above the protection tiles. Following construction, the stored topsoil would then be replaced on top of the backfilled subsoil to reinstate the trench(es) to pre-construction conditions, so far as is reasonably possible.

Plate 5.21 Example a backfilled trench (image courtesy of RWE Renewables)

5.8.3.2.2 Obstacle crossings

219. Where it has not been possible for the onshore cable corridor(s) to avoid crossing constraints such as major roads and rail crossings, major watercourses or certain ecologically sensitive features (e.g., woodland, certain hedgerows), then trenchless duct installation methodologies will be used.

220. A crossing schedule has been provided in Appendix 5.1 (Volume III) which sets out the preferred cable installation method at all obstacles encountered along the onshore cable corridor(s). This schedule will be updated throughout the EIA process as more detail regarding the environmental constraints and engineering feasibility of each crossing is known.

Horizontal Directional Drilling (HDD)

221. The primary trenchless technique used will be HDD. The HDD process involves drilling underneath the feature being avoided. The process uses a drilling head to drill a pilot hole along a predetermined profile based on an analysis of ground conditions and cable installation requirements. This pilot hole is then widened using larger drilling heads until the hole is wide enough to fit the cable ducts.

222. Bentonite is pumped to the drilling head during the drilling process to remove drill cuttings and to stabilise the hole and ensure it does not collapse. Once the HDD drilling has taken place the ducts are pulled through the drilled hole.

223. Further details of HDD are described in Section 5.7.3.1.

Plate 5.22 HDD rig (image courtesy of RWE Renewables)

Other trenchless crossing methodologies

224. In addition to HDD, alternative crossing methods such as micro tunnelling or auger boring may be considered depending on the engineering constraints posed at each location.

225. For both micro tunnelling or auger boring a circular or rectangular pit (shaft or cofferdam) is constructed each side of the feature to be crossed. These are typically 1m below the invert level of the duct to be installed. The duct is driven through the side wall from the launch pit to a reception pit. The method of driving varies to suit prevailing ground conditions.

226. Auger boring involves drilling of a pilot pipe through the ground from the launch shaft to the reception shaft. An auger is attached to the end which clears the opening of soil and is itself followed by the permanent duct. Auger boring is suitable in most cases with the exception of sands or obstructions such as cobbles or boulders.

227. Micro-tunnelling involves remote control tunnel boring machines tunnelling themselves from the launch to reception shaft conveying spoil to the launch shaft via conveyors. The permanent duct immediately follows the machine, installed by jacking from the launch pit. This method can be used in most ground as the drilling head can be configured to prevailing ground conditions.

Minor crossings methodologies (open cut trenching)

228. Other obstacles, such as certain minor road, watercourse or hedgerows crossings where trenchless techniques are not feasible will need to be crossed using alternative approaches. These are summarised below.

Minor road crossings

229. Where the onshore cable corridor(s) cross certain minor roads, tracks and Public Rights of Way (PRoW), open cut trenching methods are proposed in combination with traffic management.

230. Where appropriate, single lane traffic management would be utilised during installation with signal controls to manage traffic movement. Where the width of a road does not permit single lane traffic management and road widening is not feasible, alternative methods such as temporary road closure or diversion could be required.

231. Where standard traffic management techniques are not deemed to be suitable, it may be necessary to revert to a trenchless crossing solution.

232. The approach for each crossing would be agreed with the relevant authority prior to works beginning and would be detailed in the Construction Traffic Management Plan (CTMP). Temporary closures or diversions would only be required for the duration of time that duct installation takes place in that location. Temporary crossings of the onshore cable corridor(s) could then be installed to allow public or private access to continue where the haul road is required to remain in service. The crossings would be managed to allow safe operation.

233. Reinstatement of the trench(es) would broadly follow the same process described in Section 5.8.3.2.1, however, the road surface would be reinstated to a specification agreed with the local highway authority.

Minor watercourse crossings

234. Where certain minor watercourses such as field drains are to be crossed, the approach could be open cut trenching combined with temporary damming and diverting of the watercourse. The suitability of this method would be agreed at the detailed design stage.

235. The watercourse would be dammed at either side of the cable crossing point, typically using sandbags and ditching clay, and the water within the watercourse would be pumped or piped (for example, using a flume at bed level) across the dammed section to effectively maintain flow across the dammed section. The cable trench(es) would then be excavated within the dammed section in the manner described in Section 5.8.3.2.1 whilst ensuring that the watercourse bed materials are stored separately to subsoils. Ducts would be installed at a depth that would avoid impacts to the active channel bed.

236. Reinstatement of the trench(es) would be conducted to the pre-construction depth of the watercourse, taking care to reinstate the channel bed material and subsoils in the order that they were removed. The dams would then be removed. Temporary dams and diversion would only be required for the duration of time that duct installation takes place in that location.

237. The haul road could also require culverting or temporary bridging in these locations to allow continued access up and down the working corridor. These would remain in place for the duration that the haul road is required and would be removed once cable duct installation is complete. Some sections of the haul road may need to be retained to maintain access for the subsequent cable pulling phase.

5.8.3.3 *Cable installation*

5.8.3.3.1 Cable pull

238. Cables would be pulled through the pre-installed ducts later in the construction programme (refer to Section 5.8.5). The trench(es) would not need to be completely reopened, and the cable pull would take place from jointing bays located approximately every 500m along the onshore cable corridor(s).

239. Typically, this would be achieved by accessing the onshore cable corridor(s) directly from existing accesses (e.g., the existing road network) where possible. Sections of the haul road would need to be retained following the duct installation works. On this basis, it would be possible to reinstate sections of the haul road immediately following duct installation where access to the joint locations is possible from the existing road network. However, at this stage it is unknown exactly what proportion of the haul road would need to be retained and as a worst-case it is assumed that 100% of the haul road would remain in place throughout the cable pulling works.

240. During the cable pull and jointing works, cable drums would be delivered by heavy goods vehicle (HGV) low loader to the joint bay locations and a winch attach to the cable. The cable would then be winched off the drum from one joint pit to another, through the buried ducts. Cable jointing would be conducted once both lengths of cable have been installed within each joint bay.

241. The time required for cable pulling and the jointing process is yet to be determined.

5.8.3.3.2 Cable jointing and jointing bays

242. Joint bays would be required along the route of the onshore export cables to connect sections of cable. The joint bays would be formed upon completion of the duct installation works before the cables are installed and would typically be up to 13m long and 5m wide. The depth of the joint bays is yet to be determined, but is typically 2.05m deep, with approximately 1m of cover.

243. Joint bays would be constructed with a concrete raft floor, battered sides and also include a containerised enclosure within which the jointing takes place. Earth mats would be installed within the joint bays and at the link box positions which would consist of four earth rods driven into the ground and connected via earth tape to provide a low resistive connection to earth. The joint bays would be backfilled with CBS to ensure that the cables are stabilised from future thermo-mechanical movement. Following CBS backfill, subsoil and topsoil would be reinstated above the joint bay.

244. All excavation and reinstatement activities for the joint bays would be conducted in the same manner as that described for the cable trenching activities. At joint bay locations, a proportion of the originally excavated soils would be surplus and may require removal from the site. Adoption of a Code of Practice which complies with CL:AIRE (Contaminated Land: Applications in Real Environments) would be developed to manage the re-use and disposal of excavated soils on site.

Plate 5.23 Example jointing bay with cable pulled through (image courtesy of RWE Renewables)

5.8.3.3.3 Link boxes

245. Link boxes are required in proximity to the jointing bay locations to allow the cables to be bonded to earth to maximise cable ratings. Link boxes would not be required at all jointing bay locations, but as a worst-case scenario it is assumed that they could be required at a frequency of one every 500m. The number and placement of the link boxes would be determined as part of the detailed design.

246. The link boxes would require periodic access by technicians for inspection and testing. Where possible, the link boxes would be located adjacent to field boundaries and in accessible locations.

247. The link boxes need to be accessible during operation of the cables. The link boxes would also include a secure access panel.

Plate 5.24 Example link box following reinstatement (image courtesy of RWE Renewables)

5.8.3.4 *Reinstatement and site demobilisation*

248. Following completion of the works, all areas of the onshore cable corridor(s) including cable trenches, spoil storage, haul road and temporary construction compounds will be reinstated to their original condition. This process will be continuous during construction as each area of the works is completed. Construction access will be removed, unless expressly requested to be retained by the landowner or Essex County Council.

249. Reinstatement will include replanting of any hedgerows removed and reinstatement of any watercourses temporarily diverted during construction. Hedgerows will be replanted following the approach described in Chapter 23 Onshore Ecology (Volume I). Certain canopy trees will be restricted from being planting within 6m of the buried cables.

250. Public rights of way or other access tracks temporarily diverted during construction will also be reinstated to their original route.

5.8.3.5 *Operations and maintenance*

251. There is no ongoing requirement for regular maintenance of the onshore cables following installation, although cable would be monitored during the Project's lifetime. Access to the onshore export cables would be required to conduct emergency repairs, if necessary. In the event of such repairs, access to each field parcel along the onshore cable corridor(s) would be from existing field entry points where possible or accessing the onshore cable corridor(s) from road crossings. Emergency repairs would entail excavating the jointing bay and repulling the affected section of cable.

5.8.3.6 *Decommissioning*

252. No decision has been made regarding the final decommissioning policy for the onshore export cables, as it is recognised that industry best practice, rules and legislation change over time. It is likely the cables would be removed from the ducts and recycled, with the transition pits and ducts capped and sealed then left in situ.

5.8.4 Onshore substation and grid connection

253. The precise location of the onshore substation and grid connection is subject to ongoing consultation. At this stage in the Project's design, an onshore substation zone has been defined through the Project's site selection process, within which the Project onshore substation will be located (as shown in Figure 5.1, Volume II).

254. The onshore substation will be either an air insulated switchgear (AIS) design where the high voltage equipment is installed outdoors with open air terminations, or gas insulated switchgear (GIS) where high voltage equipment is encased and located within side a GIS building within the onshore substation site.

255. A maximum of area of 267 x 300m would be required for the substation should four circuits be included within the Project design. A landscaping / bunding area, operational drainage and a new permanent operational access are also anticipated to be required.

256. The substation is anticipated to include the following elements, across the two switchgear scenarios (some of the equipment listed below is required for AIS or GIS only):

- Control building;
- Static var compensator (SVC) buildings;
- GIS building;
- Storage / amenity building;
- Transformers (including noise enclosures);
- Switchgear;
- Reactor noise enclosures;
- Water tanks;
- Distribution Network Operation (DNO) packaged substation; and
- DNO meter cabinet.

257. The largest structures within the onshore substation listed above would be the GIS building with an approximate height of 15m; the tallest height of any structure would be lightening masts, which would be a maximum of 18m tall.

Plate 5.25 AIS control building (image courtesy of RWE Renewables)

Plate 5.26 Transformer with noise enclosure (image courtesy of RWE Renewables)

Plate 5.27 Onshore substation (image courtesy of RWE Renewables)

5.8.4.1 *Design*

258. The onshore substation will seek to adhere to principle of 'good design' for energy infrastructure as outlined in draft NPS EN-1 (BEIS, 2021). To this end, NFOW has prepared a Design Vision document (Document reference: 004577036-04) which outlines a series of design principles that will be used to guide the emerging development proposals for the Project. The principles seek to enhance and strengthen the landscape character of the North Falls setting, ensuring that a sensitive and high quality development is successfully integrated within the local community.

259. This document will underpin all ongoing design work for the Project, and will frame the development of the onshore substation design to ensure it meets the principles of good design for energy infrastructure.

5.8.4.2 *Onshore substation parameters*

260. Table 5.22 shows the main construction parameters for the onshore substation.

Table 5.22 Onshore substation parameters

Feature	Parameters
Maximum onshore substation platform footprint	267 x 300m
Maximum external equipment height (lightening masts)	18m
Construction compound indicative dimensions (m)	150 x 250m
Component transport indicative max. height on loaded transporter (m)	5m

Feature	Parameters
Component transport max. axle load for loaded transporter (tonnes)	20 tonnes

5.8.4.3 *Onshore substation construction method*

261. A new construction access and onshore substation temporary construction compound will be created in advance of construction. The location of this access will be determined in advance of consent during the Project's ongoing design process. The access will be required to facilitate access for HGVs as well as abnormal indivisible loads (AILs) for certain elements of the onshore substation's electrical infrastructure (e.g., transformers). Where there is no existing hardstanding, construction compounds would be constructed by laying a geotextile membrane or similar directly on top of the subsoil which would have stone spread over the top. All construction access and compounds would be removed and land reinstated following the completion of construction, unless requested to remain in situ by the relevant landowner and subject to the landowner obtaining any necessary consents.

262. The site would be subject to a topsoil strip, and the ground levels graded as required by the final design. Stripped material would be reused on site where possible, potentially as part of any identified bunding or screening identified through the impact assessment process.

263. Deeper soils would be excavated from areas where the ground profile needs to be lowered (cut) and moved into the areas where the ground level needs to be raised (fill). The thickness of each fill layer would need to be determined in accordance with the specification of the material and the design of the substation platform. Where the specification of the existing soils is not up to the required load bearing standard additional material may need to be imported to the site. Any excess material would be disposed of at a licenced disposal site.

264. After grading of the site is complete, excavations would then proceed with the laying of foundations, trenches and drainage. At this stage it is not known whether the foundations would be ground-bearing or piled. This would be determined by geotechnical ground investigation post-consent that would inform the detailed design. However, for the purposes of the assessment piled foundations are assumed to be required at the substation.

265. Following the completion of any cut and fill exercise and installation of drainage and foundations, the substation platform would need to be finished with a layer of imported stone fill combined with a concrete pour. The thickness of this concrete platform would be determined during detailed design based on the geotechnical ground investigation.

266. The buildings would likely be constructed from a steel frame with cladding panels. The steel frame would be fabricated off site and then erected at the substation location with the use of cranes. The cladding would be fitted once the framework is in place.

267. The substation electrical equipment would then be delivered to site and installed. Due to the size and weight of assets such as transformers, specialist delivery methods would be employed, and assets would be offloaded at site with the use of a mobile gantry crane.

268. The onshore substation would be enclosed by a temporary perimeter fence for the duration of the construction period with a permanent fence installed as part of the construction works.

269. The 400kV cables from the onshore substation to the as yet to be determined grid connection would typically be installed by direct burial method. This method will require a trench to be excavated between the onshore substation and the grid connection for the cables to be laid directly and jointed before being installed. Should any sensitive features be located along the preferred substation location to the grid connection route, then trenchless crossings may be required. See Section 5.8.3 for details of cable burial construction methods.

5.8.4.4 *Drainage*

270. A surface water drainage system would be required for the operational substation and would be designed to meet the technical requirements set out in the National Planning Policy Framework (NPPF). The surface water drainage system would use infiltration techniques which would be accommodated within the area of development, if the site gradient and underlying geology allow. If an infiltration drainage solution is not available, a pumped drainage solution may be required. Surface water discharge rates would be controlled to prevent any increase in flood risk to surrounding land from present day levels.

271. Some form of surface water attenuation could be required with sufficient capacity to retain a peak rainfall event (100-year event plus climate change). Controls would be in place to ensure that water discharge back to the surrounding area matches the existing greenfield runoff rates, discharging into the closest watercourse or surface water sewer connection. The full specification for the water attenuation and drainage system would be addressed as part of detailed design post-consent.

272. Foul drainage would be collected through a mains connection to an existing local authority sewer system if available or septic tank located within the Project boundary. The specific approach would be determined during the detailed design phase with consideration for the availability of mains connection and the number of visiting hours for site attendees during operation taken into account.

5.8.4.5 *Access*

273. A new operational access will be required to service the onshore substation. This will be required to facilitate access for light vehicles. The location of this access will be determined in advance of DCO application submission during the Project's ongoing design process.

5.8.4.6 *Screening*

274. Impacts and potential mitigation measures associated with the screening of the onshore substation are discussed in Chapter 30 Landscape and Visual Impact Assessment (Volume I). The location of soft and hard landscaping and visual screening will be determined in advance of consent during the Project's ongoing design process.

275. The Project is also exploring opportunities to deliver a minimum of 10% biodiversity net gain for the onshore elements of the Project. The biodiversity net gain delivered would be determined following completion of the latest version of the Defra Biodiversity Metric (currently version 4.0), which will be completed as part of the DCO application. As part of this, environmental enhancement is proposed to be included within the onshore substation landscaping design.

5.8.4.7 *Connection to the National Grid*

276. The 400 kV export cable connection will be underground circuit(s) running from the new North Falls onshore substation to the new National Grid East Anglia Connection Node (EACN) 400kV substation to be constructed on the Tendring Peninsula.

277. The new National Grid substation facilitates the connection of the offshore generation to the main National Electricity Transmission System and will include high voltage transformers, reactors and other typical high voltage plant and equipment.

278. National Grid's substation will be consented separately by National Grid as part of their DCO for the East Anglia GREEN project. The works to construct the new National Grid substation will be undertaken by National Grid.

279. The following is expected to be part of the new National Grid substation construction works and consented by National Grid:

- Construction of either the GIS building or concrete pad(s) for GIS and AIS options respectively, including all groundworks; and
- Provision of a construction access for HGVs to the National Grid substation and a temporary construction compound (with topsoil removed and sub-base laid) that can be used by the Contractor undertaking the cable connection works to connect the new North Falls onshore substation to the new National Grid substation.

280. The North Falls DCO application will include works for the cable connection between the new North Falls onshore substation to the new National Grid substation and some specific works to facilitate the connection within the National Grid substation as follows:

- Installation of switchgear bays in the National Grid East Anglia Connection Node 400kV Substation;
- Installation of troughs / ducts to facilitate the 400kV circuits, Protection & Control cables from the North Falls onshore substation into the switchgear bays;
- Installation and termination of the 400kV circuits and Protection & Control cables between the North Falls substation and the switchgear in the National Grid substation;
- Installation of protection and control equipment (if required) within the National Grid relay building; and
- Temporary infrastructure such as haul roads and construction compounds to facilitate access, egress, laydown, storage and welfare containers which would be placed within close proximity of the work area.

281. Although not specified at this stage, it is anticipated that the type of civils plant, equipment and activities (and therefore the associated construction noise levels), will be broadly similar to that proposed for the North Falls onshore substation works, although on a smaller scale and duration.

282. The configuration of the North Falls switchgear within the footprint of the National Grid substation will depend on a number of factors including the detailed design of the equipment required and the final layout of the new National Grid substation.

5.8.4.8 *Status of National Grid proposals*

283. National Grid have identified a search area within which they anticipate their new substation will be located. This is the hatched highlighted area illustrated on Figure 1.2 (Volume II), within the North Falls PEIR boundary. At this stage National Grid have not confirmed the proposed location of the substation within this search area, nor any information regarding the parameters of the substation.

284. Therefore, the whole search area has been included within the North Falls PEIR boundary to ensure that the works required to connect the new North Falls onshore substation to the new National Grid substation (as set out above) will be captured within our onshore project area. The North Falls red line will be refined as more information is provided by National Grid. In light of the current uncertainty regarding the proposed location of the National Grid substation, it has only been practicable to consider any likely significant effects relating to the cable connection works between the North Falls onshore substation and the new National Grid substation at a very high level in the PEIR. A full assessment, including a cumulative effects assessment, will be contained in the ES that accompanies the DCO Application.

5.8.4.9 *Operations and maintenance*

285. The onshore substation would not be manned, however access would be required periodically for routine maintenance activities. Normal operating conditions would not require lighting at the onshore substation, although low level movement detecting security lighting may be utilised for health and safety purposes. Temporary lighting during working hours would be provided during maintenance activities only.

5.8.4.10 *Decommissioning*

286. No decision has been made regarding the final decommissioning plan for the onshore project substation, as it is recognised that industry best practice, rules and legislation change over time.

287. A decommissioning requirement will be included in the draft DCO which will require a Decommissioning Management Plan to be produced prior to decommissioning. Should activities be likely to lead to materially different effects to those assessed in the ES for the DCO, then a full EIA would be required ahead of any decommissioning works being undertaken.

288. The detailed activities and methodology for decommissioning would be determined later within the Project lifetime, in line with relevant policies at that time, but would be expected to include:

- Dismantling and removal of electrical equipment;
- Removal of cabling from site;
- Removal of any building service equipment;
- Demolition of the buildings and removal of fences; and
- Landscape and reinstatement of the site.

289. The decommissioning methodology cannot be finalised until immediately prior to decommissioning but would be in line with relevant policy at that time.

5.8.5 Overall onshore construction programme

5.8.5.1 *Pre-construction works*

290. Pre-construction works are expected to take place from 2026. The main pre-construction activities are noted below and would be applicable to the onshore substation and works to install the onshore export cables:

- Demarcation of construction area;
- Ground investigations and pre-construction surveys;
- Road / junction modifications and any new junctions off existing highways;
- Pre-construction drainage - installation of buried drainage along the onshore cable corridor(s) and at the substation, which requires an understanding of the existing agricultural drainage environment;
- Hedgerow and tree removal - hedgerow and tree removal is seasonal and can be influenced by ecological factors. Removing these ahead of the main works mitigates against potential programme delays;
- Ecological mitigation - any advanced pre-construction mitigation activities, for example installation of artificial bat roosts; and
- Archaeological mitigation - pre-construction activities agreed with Historic England and local historic environment stakeholders;
- Diversion of any PRoWs (if required).

5.8.5.2 *Main works*

291. A high level indicative construction programme for the Project's onshore works is presented in Table 5.23 below. The programme illustrates the likely duration of the major installation elements, and how they may relate to one another.

292. The planned construction start date for the main works is expected to be 2026.

293. Onshore construction (landward of mean low water) would normally only take place between:

- 0700 and 1900 hours Monday to Saturday, with no activity on Sundays or bank holidays[2].

294. Outside of these hours, construction work may be required for essential activities including but not limited to:

- Continuous periods of operation, such as concrete pouring, drilling, and pulling cables through ducts; and
- Delivery of abnormal indivisible loads that may otherwise cause congestions on the local road network.

[2] Note that staff may arrive on site earlier / leave site after these working times.

Table 5.23 Indicative onshore construction programme

	Year 1				Year 2				Year 3				Year 4				Year 5			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Pre-construction works																				
Substation construction																				
Substation commissioning and site demobilisation																				
Cable route construction (including landfall and HDDs)																				

5.9 Response to potential major accidents and disasters

295. The Infrastructure Planning (EIA) Regulations 2017 (the 'EIA Regulations 2017') require significant risks to the receiving communities and environment, for example through major accidents or disasters, to be considered. Similarly, significant effects arising from the vulnerability of the North Falls project to major accidents or disasters should be considered. Relevant risks are covered in the topic chapters within this PEIR (such as flood risk in Chapter 21 Water Resources and Flood Risk, Volume I).

296. A major accident, as defined in the Control of Major Accident Hazards (COMAH) Regulations 2015 (as amended), is "an occurrence such as a major emission, fire, or explosion resulting from uncontrolled developments in the course of the operation of any establishment to which these Regulations apply, and leading to serious danger to human health or the environment (whether immediate or delayed) inside or outside the establishment, and involving one or more dangerous substances".

297. Offshore wind developments have an intrinsically low risk of causing major accidents. The wind turbines, blades, rotors, towers and foundations have an excellent safety record with a very low failure rate and are positioned many kilometres offshore away from populated areas and the public. On the rare occasion that offshore turbine blades have been lost into the sea or damage has been caused to a turbine by a fire within the nacelle, this has resulted without injury. The performance of each turbine is constantly monitored through the SCADA system sending performance data through to a central, partly automated monitoring and control centre. As a result, a problem can be quickly detected and pre-prepared safety management action plans rapidly enacted.

298. Chapter 15 Shipping and Navigation (Volume I) assesses any risks to navigational safety associated with the Project, including due to increased vessel movement to and from the offshore project area and the presence of offshore infrastructure during the life cycle of the Project.

299. Whilst exposed power cables on the seabed can pose a snagging risk to shipping and fishing vessels, the Project's export and array cables will be buried where possible to protect the cables and remove the snagging risk. Where burial is not possible, cables will be covered by cable protection. This is assessed in Chapter 15 Shipping and Navigation (Volume I).

300. Hazards associated with UXO will be managed by undertaking a UXO survey prior to construction, to enable any potential UXO to be identified, and avoided or cleared using controlled explosion techniques.

301. The buried cables onshore and offshore pose very little risk to the public as the system is designed to detect faults and 'trip out' the circuits automatically should any failure in insulation along the cable be detected.

302. The risk of substation fires is historically low, however substation fires can impact the supply of electricity and create a localised fire hazard. The highest appropriate levels of fire protection and resilience will be specified for the onshore substation to minimise fire risks. The onshore substation is located sufficiently distant from populated areas to further minimise the risk of fire hazard.

303. The lubricants, fuel and cleaning equipment required within the Project will be stored in suitable facilities designed to the relevant regulations and policy design guidance.

304. The offshore wind industry strives for the highest possible health and safety standards across the supply chain. Risks to the public during onshore construction are minimised through the use of controlled construction sites

305. NFOW recognises the importance of the highest performance levels of health and safety to be incorporated into the Project. NFOW will enact minimum safety, health and environmental requirements on all suppliers, contractors and subcontractors. NFOW will also ensure that employees that are going to work for them have undergone necessary health and safety training.

306. With a commitment to the highest health and safety standards in design and working practises enacted, none of the anticipated construction works or operational procedures is expected to pose an appreciable risk of major accidents or disasters. In conclusion, the risk of ‘major accidents and/or disasters’ occurring associated with any aspect of the Project, during the construction, operation and decommissioning phases is negligible.

5.10 References

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