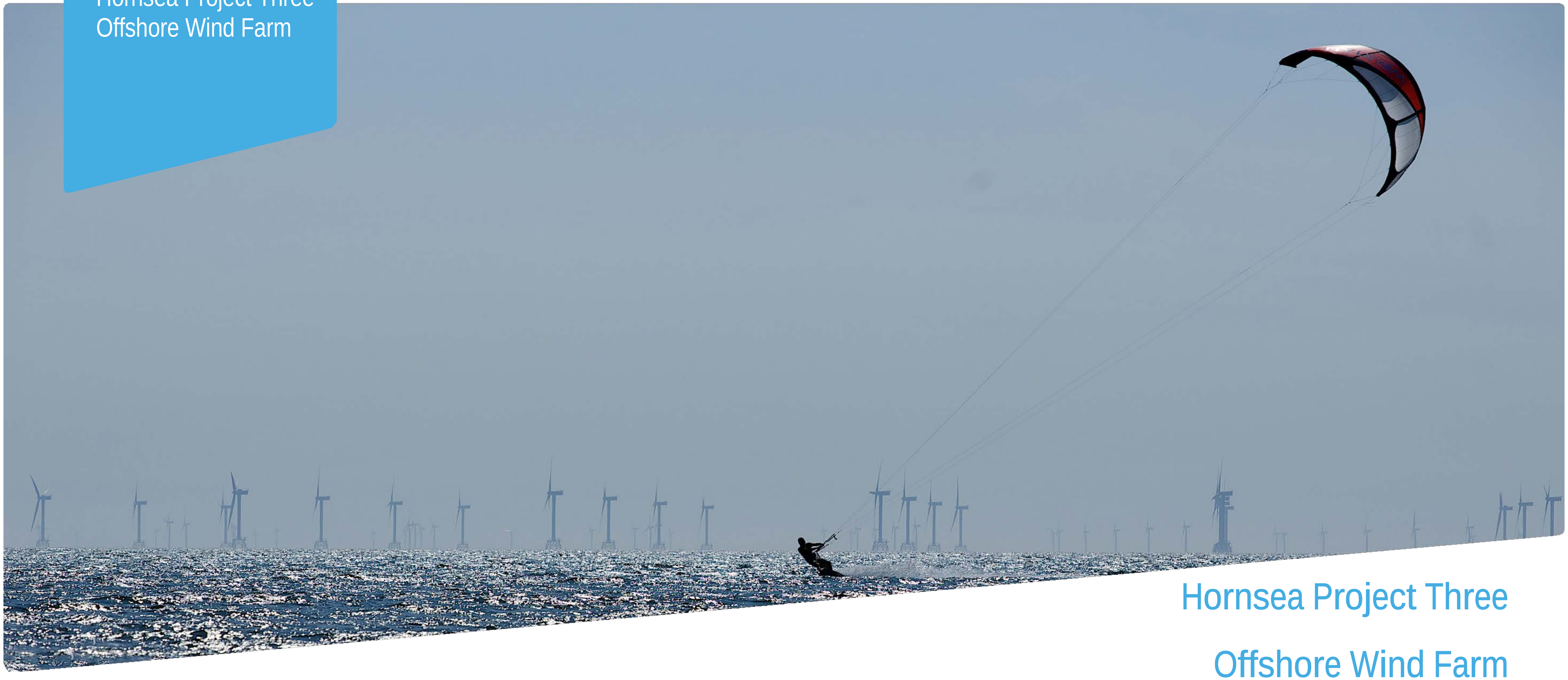
Hornsea Project Three
Offshore Wind Farm



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Offshore Wind Farm

Preliminary Environmental Information Report: Chapter 3: Project Description

Date: July 2017

Hornsea 3
Offshore Wind Farm

DONG energy

Environmental Impact Assessment

Preliminary Environmental Information Report

Volume 1

Chapter 3 – Project Description

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This report is also downloadable from the Hornsea Project Three offshore wind farm website at:
www.dongenergy.co.uk/hornseaproject3

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Front cover picture: Kite surfer near one of DONG Energy's UK offshore wind farms © DONG Energy Hornsea Project Three (UK) Ltd., 2016.

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Glossary

Term	Definition
Arisings	The soil that is displaced, or raised, from drilling to install foundations for offshore structures . For the purposes of this document, this soil is then considered spoil.
Cable Circuit	A circuit is defined as a collection of conductors necessary to transmit electric power between two points. For underground cable systems the number of conductors depends on the type of transmission technology. For HVAC transmission there will be 3 conductors (or a multiple of 3), one for each phase. These can either take the form of three conductors bundled as one cable, or three separate cables. For HVDC transmission only two conductors (or multiple of 2) are necessary (assuming an earth return is not used). These typically are separate cables but may be attached together offshore for ease of installation. If there are multiple circuits between two points they typically will be differentiated by their ability to be isolated (by circuit breaker or disconnector) at either end. The circuit may or may not include one or more fibre optic cables for the purpose of control, monitoring, protection or general communications.
Design Envelope	A description of the range of possible elements which make up the project design options under consideration, as set out in detail in Chapter 3: Project Description. This envelope is used to define the project for Environmental Impact Assessment (EIA) purposes when the exact engineering parameters are not yet known. This is also often referred to as the "Rochdale Envelope.
Dynamic Positioning (DP)	An advanced autopilot system installed on vessels that consists of thrusters, GPS, and a control unit. The system is capable of automatically holding a vessel at location and heading specified by the operator.
Edge Weighted Layouts	A type of wind turbine layout where the spacing at all or some of the boundary of the wind farm is less than the spacing between some or all of the inter array turbines.
Spoil	Waste soil or sediment that is excavated or drilled out as part of the Project's installation works.
Trenchless Techniques	Also referred to as trenchless crossing techniques or trenchless methods. These techniques include HDD, thrust boring, auger boring, and pipe ramming, which allow ducts to be installed under an obstruction without breaking open the ground and digging a trench.
Weather Downtime	Hours or days when the weather conditions, including wave, tide, current, and/or wind, prevent work.
Wind Turbine Generator	All of the components of a wind turbine, including the tower, nacelle, and rotor.

Acronyms

Acronym	Description
AFL	Agreement for Lease
BEIS	Department for Business, Energy and Industrial Strategy (formerly DECC)
CAA	Civil Aviation Authority
CEMP	Construction Environment Management Plan
DCO	Development Consent Order
DECC	Department of Energy and Climate Change (Now BEIS)
DNO	Distribution Network Operator
DP	Dynamic Positioning
DRA	Design Risk Assessment
EIA	Environmental Impact Assessment
GBF	Gravity Base Foundation
HAT	Highest Astronomical Tide
HDD	Horizontal Directional Drilling
HGV	Heavy Goods Vehicle
HSE	Health, Safety and Environment
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IALA	International Association of Lighthouse Authorities
IPC	Infrastructure Planning Commission
JNCC	Joint Nature Conservation Committee
LAT	Lowest Astronomical Tide
MCA	Maritime and Coastguard Agency
MHWS	Mean High Water Springs
MIND	Mass Impregnated Non-Draining
NPS EN-1	Overarching National Policy Statement for Energy
NPS EN-3	National Policy Statement for Renewable Energy Infrastructure
O&M	Operations and Maintenance

Acronym	Description
OAP	Offshore Accomodation Platform
OREI	Offshore Renewable Energy Installations
OSS	Offshore Substations
PAX	Passengers
PIER	Preliminary Environmental Information Report
PINS	Planning Inspectorate
PLGR	Pre-Lay Grapnel Run
PRoW	Public Rights of Way
ROV	Remotely Operated Vehicle
RPS	RPS Planning and Development Limited
SCADA	Supervisory Control and Data Acquisition
SWMP	Site Waste Management Plan
TCE	The Crown Estate
THLS	Trinity House Lighthouse Service
TJB	Transition Joint Bay
UXO	Unexploded Ordnance
VSC	Voltage Source Converter
WTG	Wind Turbine Generator
XLPE	Cross Linked Polyethylene
ZDA	Zone Development Agreement
ZEA	Zone Environmental Appraisal

Units

Unit	Description
AC	Alternating Current (electricity)
GW	Gigawatt
km	Kilometre
kV	Kilovolt
m/s	Metres Per Second
MW	Megawatt

3. Project Description

3.1 Introduction

3.1.1.1 DONG Energy Power (UK) Ltd. (hereafter referred to as DONG Energy), on behalf of DONG Energy Hornsea Project Three (UK) Ltd. is promoting the development of the Hornsea Project Three Offshore Wind Farm (hereafter referred to as Hornsea Three).

3.1.1.2 This chapter of the Preliminary Environmental Information Report (PEIR) provides an outline description of the potential design of Hornsea Three, based on preliminary conceptual design information and current understanding of the environment from initial survey work. It sets out the Hornsea Three design and components for both the onshore and offshore infrastructure, as well as the main activities associated with the construction, operation and maintenance, and decommissioning of Hornsea Three.

3.1.1.3 At this early stage in the Hornsea Three development process, the project description is indicative and the 'envelope' has been designed to include sufficient flexibility to accommodate further project refinement during detailed design, post consent. This chapter therefore sets out a series of options and parameters for which values are shown.

3.1.1.4 In order to avoid excessive conservatism in the assessments, the parameters assessed throughout this PEIR are not a combination of the worst case parameters for each component. For example we would not use both the maximum number of turbines and the parameters related to the largest turbine type within the envelope, as this is not a feasible scenario. Instead the worst case is chosen on a receptor by receptor and an impact by impact basis, based on a range of scenarios, whereby the physical size of the turbines is related to their number and the sizes of the associated infrastructure such as turbine foundations. These scenarios generally assume either the maximum number of turbines with parameters related to the use of the smallest turbine type, or the largest parameters in the envelope, and fewer turbines. The details of these maximum design scenarios is set out within the topic chapters, of this PEIR (volumes two to three) themselves.

3.1.1.5 It should also be noted that this project description does not refer directly to the capacity of the turbines, but rather their physical dimensions. In recent years the capacity of the current generation of turbines has become more flexible, and may be different depending on the environmental conditions at the sites. It is also noted that the EIA assessments are not linked directly to the turbine capacity (but rather it's physical dimensions such as tip height and rotor diameter), therefore it is not considered appropriate to constrain the envelope based on turbine capacity.

3.1.1.6 The final design will be refined later in the project development from within the parameters stated here. Hornsea Three will also, throughout the EIA process, seek to refine the proposed values and to provide more detailed realistic maximum design scenarios where required. A further refined project description will be provided in the Environmental Statement that will accompany the application for Development Consent.

3.2 Design envelope approach

3.2.1.1 The use of the Design Envelope approach has been recognised in the Overarching National Policy Statement (NPS) for Energy (EN-1) (DECC, 2011a) and the NPS for Renewable Energy Infrastructure (EN-3) (DECC, 2011b). This approach has been used in the majority of offshore wind farm applications.

3.2.1.2 In the case of offshore wind farms, NPS EN-3 (paragraph 2.6.42) 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;*
- *Cable type and cable route; and*
- *Exact locations of offshore and/or onshore HVDC converter/HVAC substations*."

3.2.1.3 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 (as set out in EN-1 paragraph 4.2.8) to ensure that the project as it may be constructed has been properly assessed (the Rochdale [Design] Envelope)". (DECC, 2011b).

3.2.1.4 NPS EN-3 also states (in footnote 23, on page 32) that:

"The 'Rochdale [Design] Envelope' is a series of maximum extents of a project for which the significant effects are established. The detailed design of the project can then vary within this 'envelope' without rendering the ES [Environmental Statement] inadequate".

3.2.1.5 The Design Envelope approach is widely recognised and is consistent with PINS Advice Note Nine: Rochdale Envelope (PINS, 2012) which states (page 11, conclusions) that:

"*The 'Rochdale Envelope' is an acknowledged way of dealing with an application comprising EIA development where details of a project have not been resolved at the time when the application is submitted*".

3.2.1.6 Throughout the PEIR the Design Envelope (otherwise known as the "Rochdale Envelope") Approach has been taken to allow meaningful assessments of Hornsea Three to proceed, whilst still allowing reasonable flexibility for future project design decisions.

3.3 Hornsea Three boundary

3.3.1.1 The boundary of Hornsea Three is delineated on Figure 3.1 below. Hornsea Three consists of the:

- Hornsea Three array area: This is where the offshore wind farm will be located, which will include the turbines, wind turbine and offshore structure foundations, array cables, offshore accommodation platforms and a range of offshore substations as well as offshore interconnector cables and export cables;
- Hornsea Three offshore cable corridor: This is where the permanent offshore electrical infrastructure (offshore export cable(s), as well as the offshore HVAC booster station(s) and their foundations, if required), (see Table 3.28 below) will be located; and
- Hornsea Three onshore cable corridor search area: This is where the permanent onshore electrical infrastructure (onshore export cable(s), as well as the onshore HVAC booster station, if required), onshore HVDC converter/HVAC substation and connections to the National Grid will be located.

3.4 The Agreement for Lease (AfL) area

3.4.1.1 The Agreement for Lease (AfL) from The Crown Estate (TCE) allows DONG Energy, as a prospective tenant of the AfL, to carry out investigations, such as survey activities, to identify the potential design within the Hornsea Three array area. It allows Hornsea Three to understand environmental sensitivities that may exist, in advance of submitting the consent application, whilst and before applying to TCE for a lease for the lifetime of the wind farm. As noted under NPS EN-3, the detailed design cannot be proposed at this stage, however further information on the site will inform the refinement of the Design Envelope post consent.

3.4.1.2 The AfL area for the Hornsea Three array area covers approximately 696 km^2 and is broadly a diamond shape with a length of approximately 29 km west to east and 35 km north to south. The AfL area is where the offshore infrastructure, such as the turbines, offshore substation(s) and array cables, will be located. This area is hereafter referred to as the Hornsea Three array area throughout this chapter (see Figure 3.1).

3.4.1.3 Hornsea Three does not yet have an AfL area for the offshore cable corridor. Detail of the Hornsea Three offshore cable corridor AfL area will be published in the Environmental Statement.

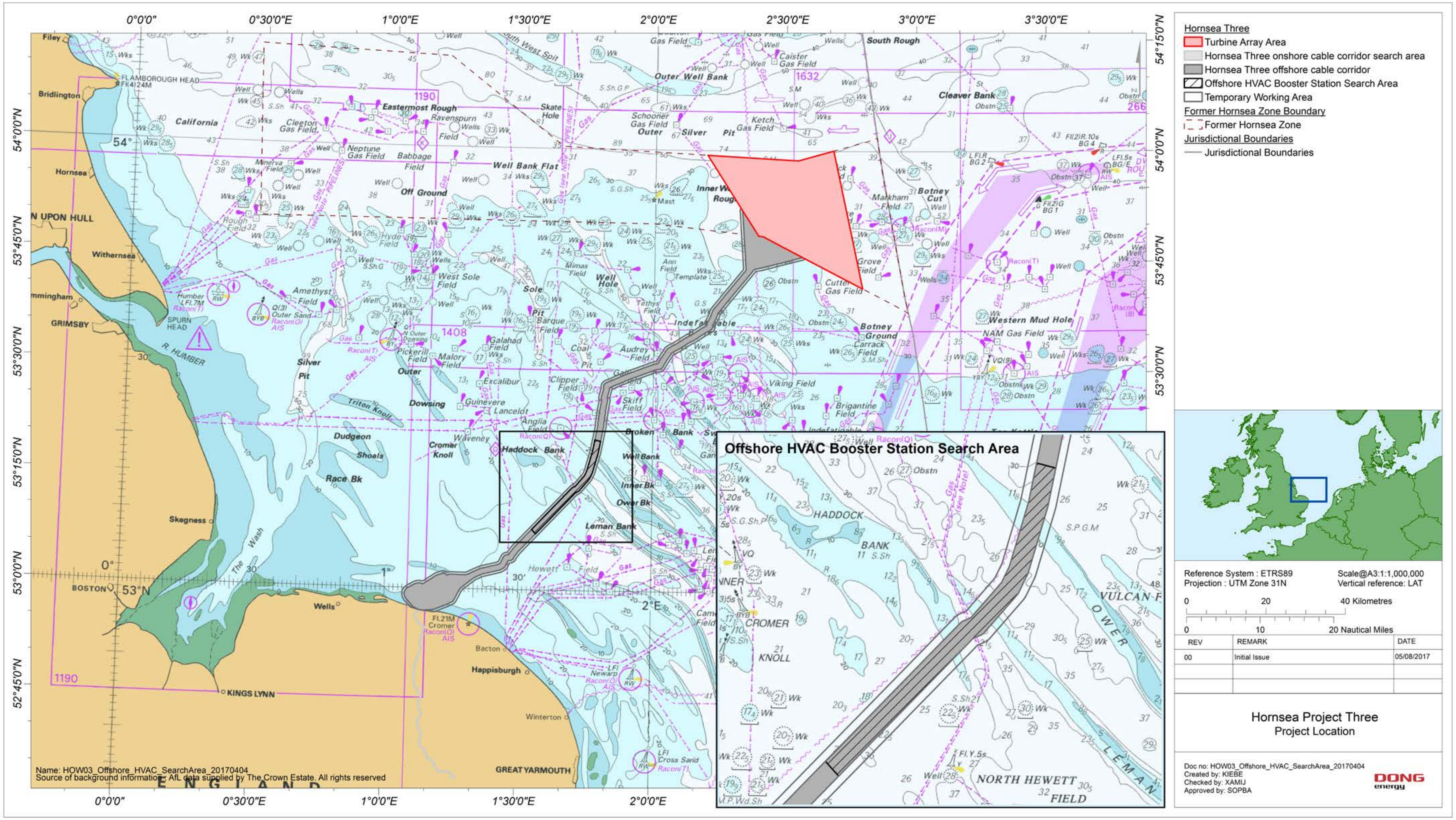


Figure 3.1: Overview of the Hornsea Three project location.

3.5 Project infrastructure overview

3.5.1.1 Hornsea Three will comprise of turbines and all infrastructure required to transmit the power generated by the turbines to the existing Norwich Main National Grid substation, which is located south of Norwich. It will also comprise any offshore infrastructure required to operate and maintain the wind farm.

3.5.1.2 Hornsea Three will have a maximum of 342 turbines, which will could supply up to 2.4 GW of power as measured at offshore metering point at the offshore substations. Hornsea Three will also have up to a total of up to 16 offshore substations (OSS) and up to three offshore accommodation platforms (OAP) as part of the power transmission system and operation and maintenance set-up, and up to six offshore export cables to transmit power to the national grid. The onshore infrastructure will consist of up to 18 onshore export cables buried in up to six trenches. It may also include an onshore HVAC booster station and an onshore HVDC converter/HVAC substation to allow the power to be transferred to the National Grid via the existing Norwich Main National Grid substation.

3.5.1.3 The maximum proposed number of turbines has been reduced from the 400 initially proposed in the Scoping Report. This will mitigate impacts on a number of receptors including, but not limited to, those associated with the following chapters;

- Offshore Ornithology;
- Benthic Ecology;
- Commercial Fisheries;
- Shipping and Navigation;

3.5.1.4 Hornsea Three may use HVAC or HVDC transmission, or could use a combination of both technologies in separate electrical systems. Hornsea Three is applying for both HVAC and HVDC transmission to allow for suitable flexibility to ensure a low cost of energy to the UK consumer and to facilitate successful completion of Hornsea Three in a competitive market. If a combination of the two technologies is used, the total infrastructure installed will not exceed the maximum values assessed within this application.

3.5.1.5 The key components of Hornsea Three are likely to include (also shown in Figure 3.2):

- Offshore turbines;
- Foundations (for turbines, offshore substation platforms, and offshore accommodation platforms);
- Scour protection;
- Offshore accommodation platform(s);
- Array cables linking the individual turbines to offshore substations; and
- HVAC or/and HVDC transmission system including either:
    - HVAC:
        - Offshore transformer substation(s);
        - Offshore interconnector cables(s);
        - Offshore export cable(s);
        - Offshore HVAC booster station(s) (unless specified otherwise this refers to both Surface and Subsea designs. See para 3.6.8.17 to 3.6.8.28));
        - Onshore export cable(s);
        - Onshore HVAC booster station (either instead of, or as well as offshore HVAC booster station(s));
        - Onshore HVDC converter substation / Onshore HVAC substation.; and
        - Grid connection export cable(s).
    - HVDC:
        - Offshore transformer substation(s);
        - Offshore interconnector cables(s);
        - Offshore HVDC converter substation(s);
        - Offshore export cables(s);
        - Onshore export cables(s);
        - Onshore HVDC converter/HVAC substation; and
        - Grid connection export cable(s).

3.5.1.6 It is likely that the Hornsea Three components will be fabricated at a number of manufacturing sites across Europe, to be determined as part of a competitive tendering process upon award of consent and the completion by DONG Energy of a Final Investment Decision (FID).) A construction base (port facility) may be used to stockpile some components, such as foundations and turbines, before delivery to the Hornsea Three array area for installation. Other components, such as pre-fabricated offshore substation units, may be delivered directly to the Hornsea Three array area when required. An operations and maintenance onshore base may be provided to support the operating wind farm after construction.

3.5.1.7 Hornsea Three may be constructed in a single phase, or in up to three phases. Although the total durations for each component would not exceed those stated in this document, there may be periods where work stops as one phase is completed and is initiated again for the following phase after a gap.

3.5.1.8 The offshore wind farm and associated grid connection components are briefly described in the following sections. Maximum design parameters (dimensions and/or numbers where appropriate) are provided to indicate the potential scale of the proposed offshore wind farm as well as informing the EIA process. Based on the findings of the consultation and EIA process, a further refined and detailed project description will be provided in the final Environmental Statement.

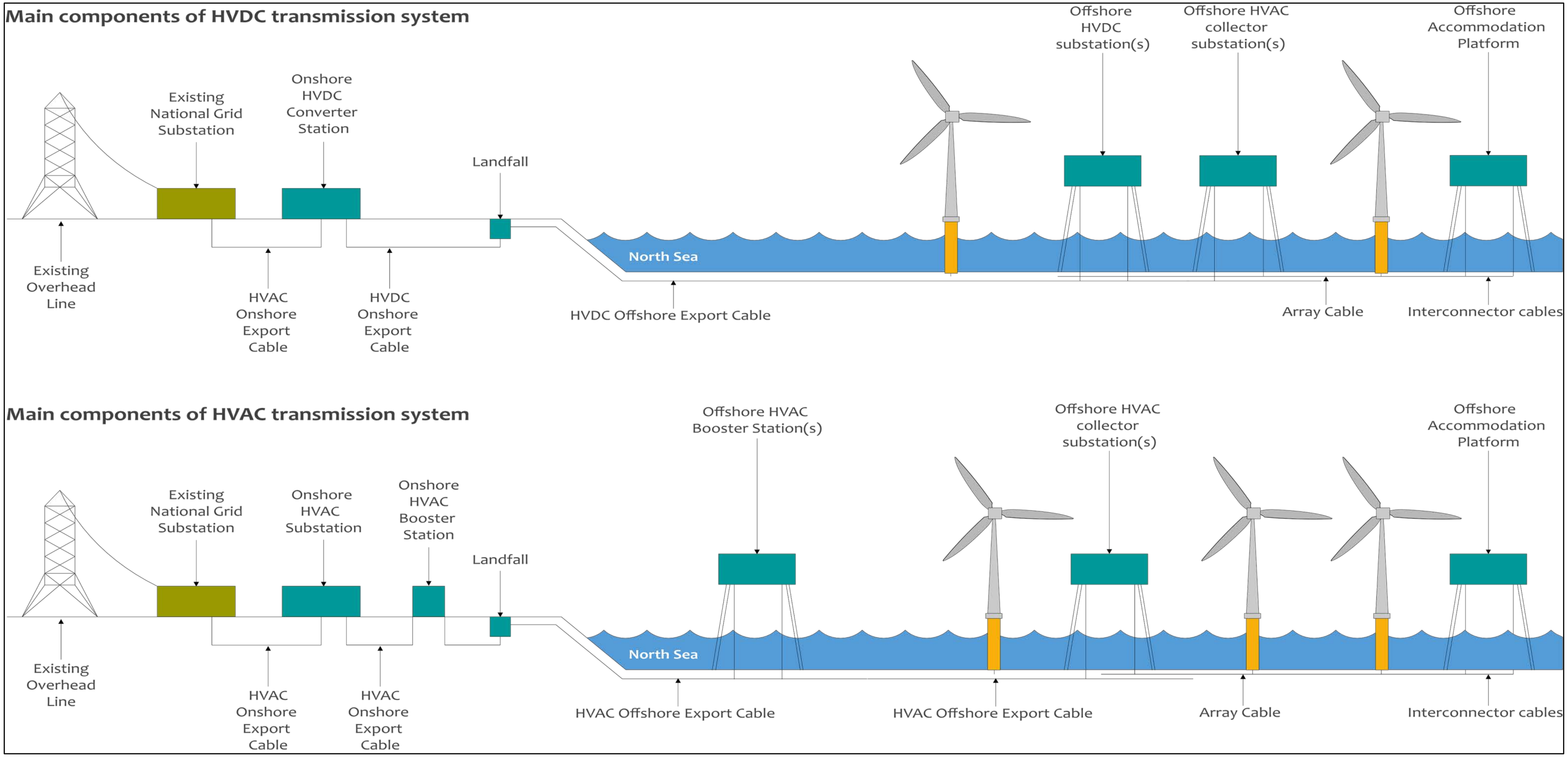


Figure 3.2: Overview of Hornsea Three infrastructure.

3.6 Offshore infrastructure

3.6.1 Turbines

Design

3.6.1.1 Hornsea Three requires flexibility in wind turbine choice to ensure that anticipated changes in available technology and project economics can be accommodated within the Hornsea Three design. The Design Envelope therefore sets maximum and, where relevant, minimum realistic worst case scenario parameters against which likely significant environmental effects can be assessed. It is possible that more than one turbine type may be selected.

3.6.1.2 Hornsea Three may construct up to 342 turbines. A range of turbine models will be considered; however, they are likely to all follow the traditional offshore wind turbine design with three blades and a horizontal rotor axis.

3.6.1.3 The blades will be connected to a central hub, forming a rotor which turns a shaft connected to the generator or gearbox (if required). The generator and gearbox will be located within a containing structure known as the nacelle situated adjacent to the rotor hub. The nacelle will be supported by a tower structure affixed to the transition piece or foundation. The nacelle will be able to rotate or 'yaw' on the vertical axis in order to face the oncoming wind direction. An illustration of this design can be seen in Figure 3.3 and a picture of a turbine at Walney offshore wind farm is shown in Figure 3.4.

3.6.1.4 The maximum design scenario for turbines describes two scenarios, one with the largest number of turbines, using smaller parameters, and one with the largest turbine, using fewer turbines. The most numerous turbine scenario has a maximum of 342 turbines. The maximum size turbine has a rotor diameter of 265 m and a maximum blade tip height of 325 m relative to LAT (highest point of the structure). The minimum distance between the bottom of the blade and the water surface will be 34.97 m LAT. All turbines will be marked for aviation and navigation purposes.

3.6.1.5 The Maximum design scenario for the Hornsea Three turbines is shown in Table 3.1.

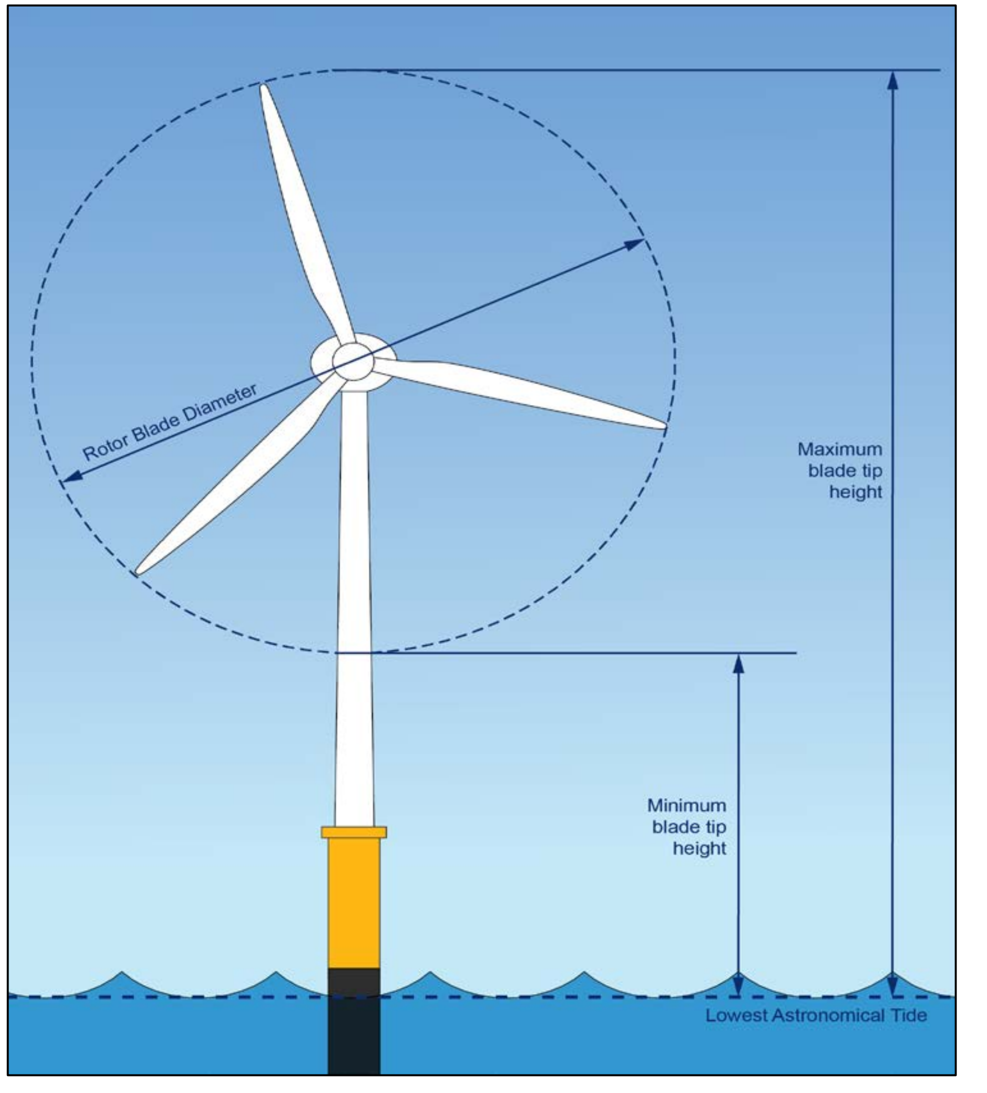


Figure 3.3: Schematic of an offshore wind turbine.

Table 3.1: Maximum design scenario: turbines.

Parameter	Maximum design scenario – Most Numerous Turbine	Maximum design scenario– Largest Turbine
Number of turbines	342	160
Minimum height of lowest blade tip above LAT (m)	34.97	34.97
Maximum blade tip height above LAT (m)	240	325
Maximum rotor blade diameter (m)	185	265

Figure 3.4: Turbines at Walney offshore wind farm.

Access

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

Oils and fluids

3.6.1.7 Each turbine will contain components that require lubricating oils, hydraulic oils and coolants for operation. Table 3.2 shows indicative requirements for these oils and fluids in a single offshore wind turbine.

Table 3.2: Maximum design scenario: wind turbine oils and fluids for a single turbine.

Parameter	Maximum design envelope
Grease (l)	1,300
Hydraulic oil (l)	20,000
Gear oil (l)	2,000
Total lubricants (l)	~25,000
Nitrogen (l)	80,000
Transformer silicon/ester oil (l/kg)	7,000
Diesel Fuel (l)	2,000
SF6 (kg)	6
Glycol / Coolants (l)	13,000

Control systems

3.6.1.8 Turbines operate within a set wind speed range. At approximately 3 m/s the wind turbine will start to generate electricity and at around 15 m/s they will reach maximum output. At around 25 m/s the turbine output starts to reduce towards zero. This enables the turbine to shut down in high wind speeds to protect the turbine and foundation, whilst enabling a gradual ramp-down of the power output to support the operation of the National Grid.

3.6.1.9 Each turbine will have its own control system to carry out functions like yaw control and ramp down in high wind speeds. All the turbines are also connected to a central Supervisory Control And Data Acquisition (SCADA) system for control of the wind farm remotely. This allows functions such as remote turbine shutdown if faults occur. The SCADA system will communicate with the wind farm via fibre optic cables, microwave, or satellite links. Individual turbines can also be controlled manually from within the turbine nacelle or tower base in order to control the turbine for commissioning or maintenance activities.

Installation

3.6.1.10 Generally, turbines are installed using the following process:

- Turbine components are picked up from a port in the UK or Northern Europe by an installation vessel. This vessel will typically be a Jack-Up Vessel (JUV) to ensure a stable platform for installation vessels when on site. Generally, blades, nacelles, and towers for a number of turbines are loaded separately onto the vessel;
- The installation vessel will then transit to the Hornsea Three array area and the components will be lifted onto the existing foundation or foundation and transition piece, by the crane on the installation vessel. Each turbine will be assembled on site in this fashion with technicians fastening components together as they are lifted into place. The exact methodology for the assembly is dependent on turbine type and installation contractor, and will be defined in the pre-construction phase after grant of consent; or
- Alternatively, the turbine components may be loaded onto barges or dedicated transport vessels at port, and installed as above by an installation vessel that remains on site throughout the installation campaign.

3.6.1.11 Each installation vessel or barge may be assisted by a range of support vessels. These are typically smaller vessels that may be tugs, guard vessels, anchor handling vessels, or similar. These vessels will be primarily making the same movements to, from and around the windfarm as the installation vessels they are supporting.

3.6.1.12 For the EIA, the following assumptions are made on the maximum number of vessels and the number of return trips to the Hornsea Three array area from port that are required throughout the turbine installation campaign.

Table 3.3: Wind turbine installation assumptions.

Vessel Type	Maximum number of vessels	Maximum number of return trips per vessel type
Installation vessel	4	342
Support vessels	24	2,052
Transport vessels	12	1,026
Helicopter support	-	257

3.6.1.13 JUVs are assumed to have up to six legs with an area of 170 m^2 per foot. The total duration of the installation campaign for turbines is expected to be a maximum of 30 months.

3.6.2 Wind turbine and surface infrastructure layouts

3.6.2.1 Designing and optimising the layout of the turbines and other offshore surface infrastructure (offshore substations and offshore accommodation platforms) is a complex, iterative process taking into account a large number of inputs and constraints including;

- Site conditions:
  - Wind speed and direction;
  - Water depth;
  - Ground conditions;
  - Environmental constraints (anthropogenic and natural);
  - Seabed obstructions (e.g. wrecks, Unexploded ordnance (UXO), existing cables); and
  - Pre-determined boundaries (AfL area).
- Design considerations:
  - Turbine type;
  - Installation set-up;
  - Foundation design;
  - Electrical design; and
  - Operation and maintenance requirements.

3.6.2.2 The Hornsea Three layouts will have a spacing between neighbouring turbines of no less than 1 km. The layout may use dense borders, but will not breach the spacing limitation stated above.

3.6.2.3 In order to inform the EIA, Hornsea Three has identified two indicative layout scenarios. The indicative layout scenarios have been used within the EIA where appropriate. Layout A (Figure 3.5) includes the maximum number of structures (342 turbines and 19 platforms (offshore accommodation and substations)). It includes a dense border at an approximate spacing of 1 km, and varied internal spacing. As the locations of the infrastructure is not yet defined, the layouts do not distinguish between what type of infrastructure is placed in each location. Individual assessment chapters have therefore made assumptions as to which locations are turbines or platforms in order to inform the assessment. Layout B is shown in Figure 3.6. This layout shows an indicative scenario with larger turbines, and hence greater spacing between turbine locations. The total number of locations in this layout is 125, the border spacing is approximately 5.6 km and the internal spacing is varied.

3.6.2.4 The final layout will be designed after the consent has been granted, taking into account the constraints listed in paragraph 3.6.2.1 above.

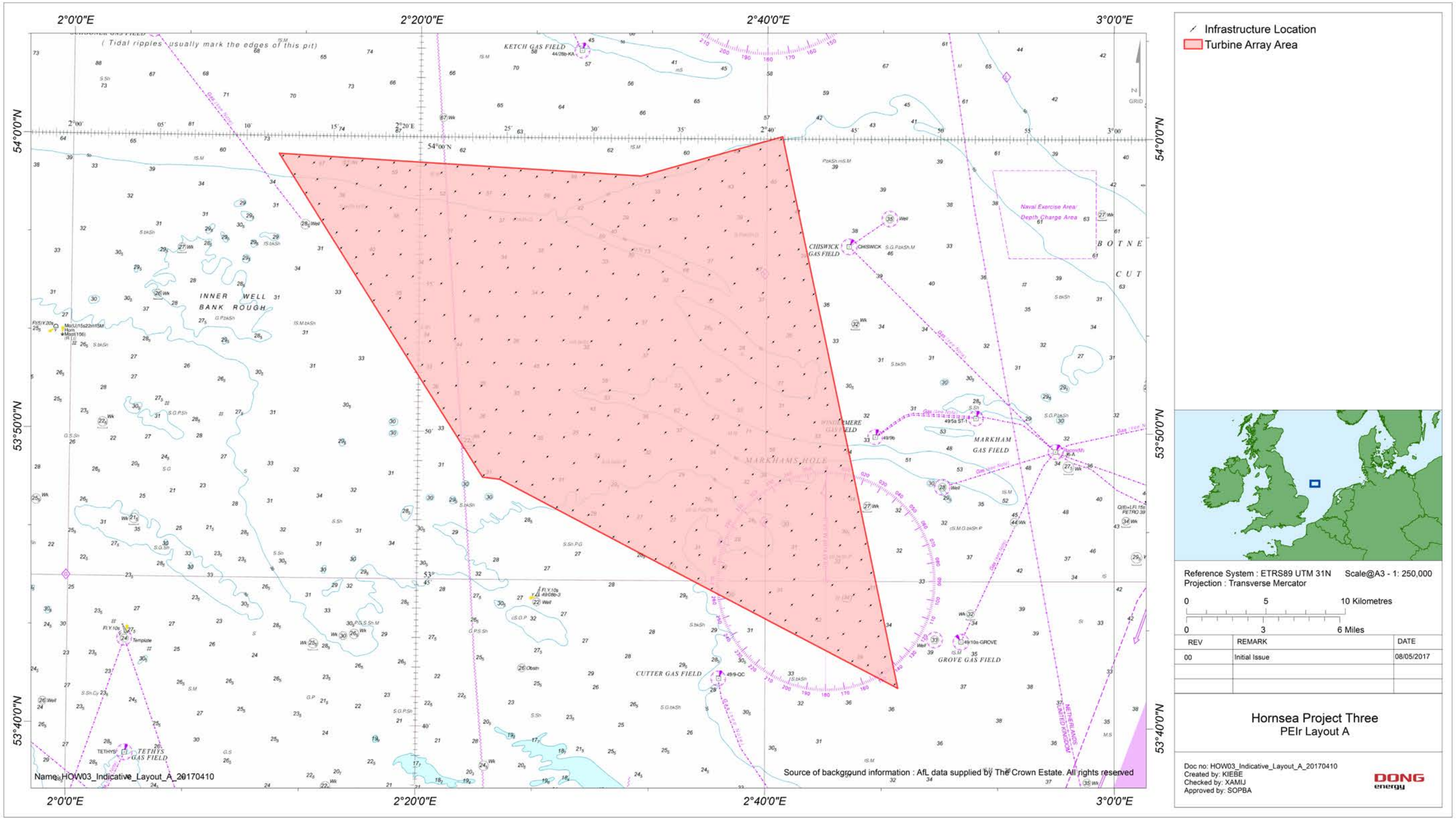


Figure 3.5: Indicative Layout A.

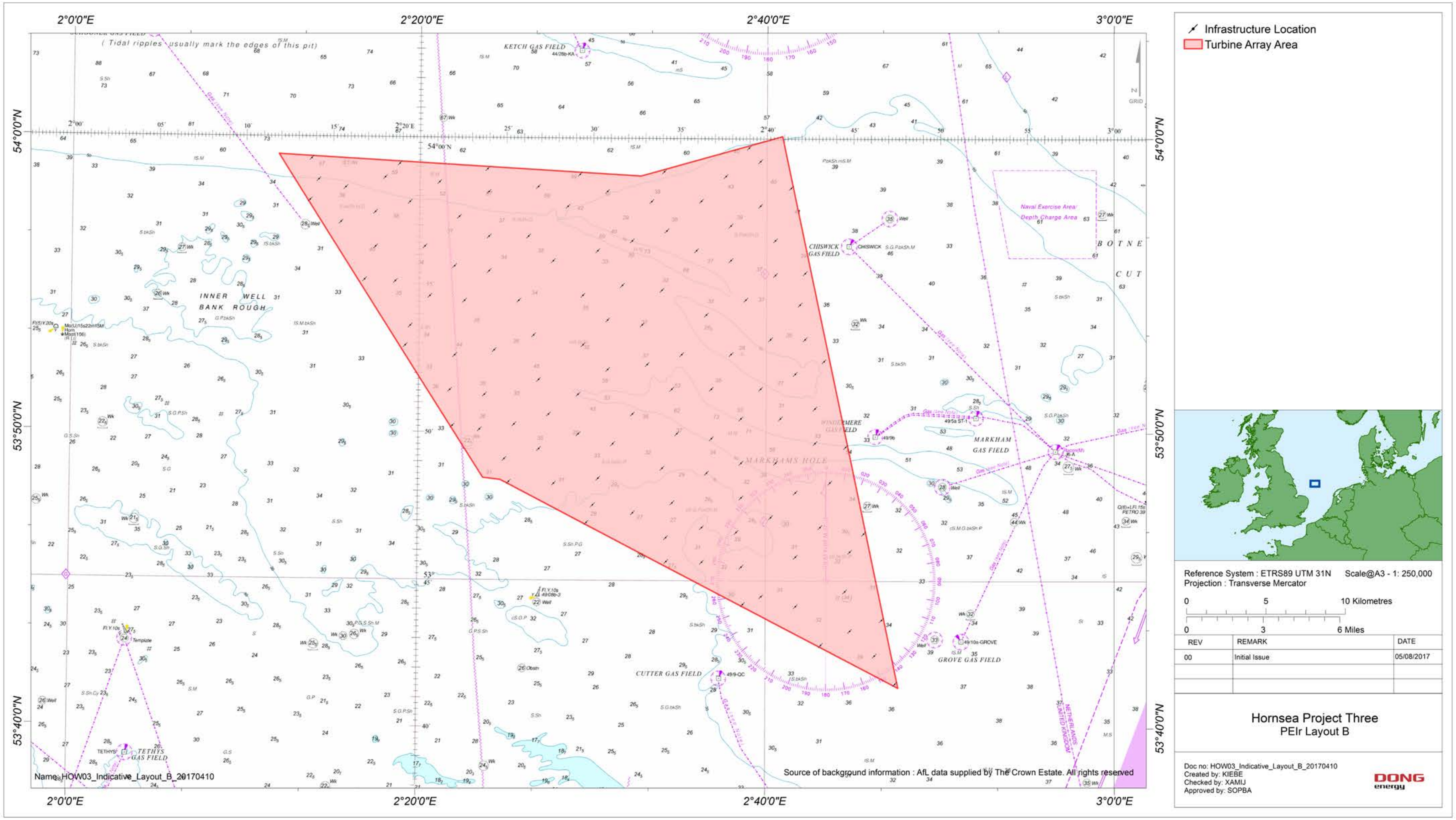


Figure 3.6: Indicative Layout B.

3.6.3 Aids to navigation, colour, marking and lighting

3.6.3.1 Each turbine (including colours, marking and lighting) and any required aids to navigation will be designed in accordance with relevant guidance from Trinity House, the CAA and the MCA. The positions of all infrastructure (including turbines, substations, platforms and cables) will be conveyed to the UK Hydrographic Office so that they can be incorporated into Admiralty Charts and the Notice to Mariners procedures.

3.6.4 Foundations for turbines, offshore substations and offshore accommodation platform

3.6.4.1 The turbines, offshore substation(s) and offshore accommodation platform(s) are attached to the seabed by foundation structures or anchor systems. There are a number of foundation types that are being considered for Hornsea Three. Hornsea Three requires flexibility in foundation choice to ensure that anticipated changes in available technology and project economics can be accommodated within the Hornsea Three design. The final selection will depend on factors including turbine soil conditions, wave and tidal conditions, project economics and procurement approach. The range of foundation options to be used for turbines and each type of offshore substation can be seen in Table 3.4 below. As outlined in Table 3.4, the foundation types defined for turbines may also be used to support offshore substation structures or offshore accommodation platforms. However there are also a range of foundation types that are only intended to be used for specific offshore substation types. Consequently, the EIA will consider a range of types, including monopiles, suction bucket jacket foundations, piled jacket foundations, mono suction buckets, gravity base structures and floating foundations.

3.6.4.2 Some form of seabed preparation may be required for each foundation type. Seabed preparations may include seabed levelling, and removing surface and subsurface debris such as (for example) boulders, lost fishing nets or lost anchors. If debris is present below the seabed surface, then excavation may be required for access and removal. Following consultation with the MMO and Ministry of Defence (MoD), any unexploded ordnance (UXO) found with a potential to contain live ammunition may be detonated on site and any remaining debris removed. However, as the location and number of UXO detonations is currently unknown and will not be known until the final design of Hornsea Three, it is not possible to assess the detonation of UXO until after consent is granted and the exact ground conditions are known. This activity (UXO detonation) will therefore not be scoped as part of the EIA and a separate Marine Licence(s) will be sought, if and when required.

3.6.4.3 The foundations will be fabricated offsite, stored at a suitable port facility and transported to site as needed. Specialist vessels will be needed to transport and install foundations. A filter layer and/or scour protection layer (typically rock) may be needed on the seabed and will be installed either before and/or after foundation installation.

3.6.4.4 The maximum envelope values for the sum of the project foundations can be seen in Table 3.5.

3.6.4.5 Further details on the foundation types that will be considered in the EIA are described in the following sections.

Table 3.4: Foundation options for turbines and offshore structures.

	Turbine	Offshore transformer substation	Offshore HVAC booster station	Offshore HVDC converter substation	Offshore accommodation platform
Number of structures	342	12	4 [a] (6 subsea)	4 [a]	3
Monopile	Y	Y	Y	Y	Y
Mono suction bucket	Y	Y	Y	Y	Y
Piled jacket	Y	Y	Y	Y	Y
Suction bucket jacket	Y	Y	Y	Y	Y
Gravity base	Y	Y	Y	Y	Y
Floating	Y	N	N	N	N
OSS suction bucket jacket	N	Y	Y	Y	Y
OSS piled jacket	N	Y	Y	Y	Y
Box-type gravity base	N	Y	Y	Y	N
Converter piled jacket	N	N	N	Y	N
Converter suction bucket jacket	N	N	N	Y	N
Pontoon GBS 1	N	N	N	Y	N
Pontoon GBS 2	N	N	N	Y	N

a Offshore HVDC converter substation is mutually exclusive with HVAC booster station in a single circuit. Therefore these two figures should not be combined in the total number, i.e. the maximum number of structures is 361.

Table 3.5: Maximum envelope values for all project foundations.

Worst case combined wind turbine, substation and accommodation platform foundations	Maximum design scenario
Total number of structures	361
Seabed area – preparation (m^2)	1,154,779
Seabed area – structure (m^2)	616,934
Seabed area – scour protection (m^2)	1,535,001
Seabed area – total (m^2)	2,116,108
Spoil volume (m^3)	2,459,850
Gravel bed volume (m^3)	1,732,169
Scour protection volume (m^3)	3,043,084
Pile-structure grout volume (m^3)	63,955
Structure-seabed grout volume (m^3)	313,769

Foundations for wind turbines, offshore substations and accommodation platforms

Monopile foundations

Design

3.6.4.6 Monopile foundations (MP) typically consist of a single steel tubular section, consisting of a number of sections of rolled steel plate welded together. A transition piece (TP) is fitted over the monopile and secured via bolts or grout. The transition piece may include boat landing features, ladders, a crane, and other ancillary components as well as a flange for connection to the wind turbine tower (Figure 3.7). The TP is usually painted yellow and marked according to relevant regulatory guidance and may be installed separately following the monopile installation. The maximum maximum design scenario dimensions of the monopile foundations can be seen in Table 3.6 below.

Table 3.6: Maximum design scenario: monopile.

Parameter	Maximum design scenario
Diameter of monopile [a] (m)	15
Diameter of transition piece (m)	15
Embedment depth (below seabed) (m)	40
Hammer energy (kJ)	5,000

a For largest proposed turbine (noting that for the maximum number of turbines, the largest realistic worst case monopile diameter will be smaller).

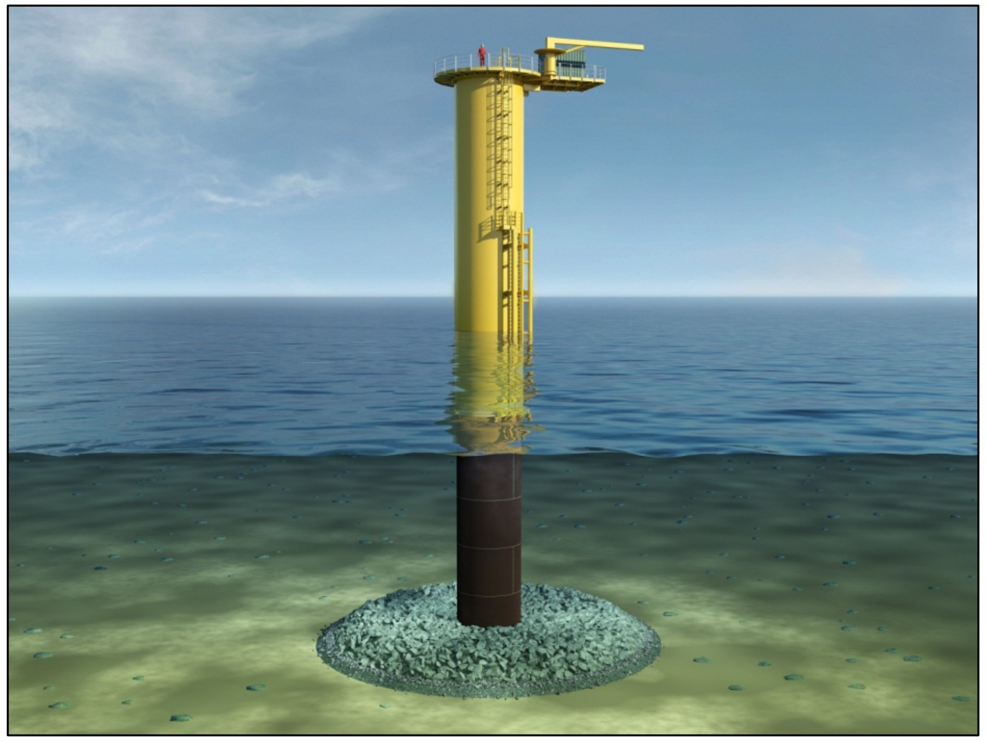


Figure 3.7: A monopile foundation and transition piece.

Installation

3.6.4.7 Monopiles and transition pieces will be transported to site either on the installation vessel (either JUV or Dynamic Positioning Vessel (DPV)), or on feeder barges, as described in paragraph 3.6.1.10. Monopiles can also be sealed and floated to site.

3.6.4.8 Once on site, the monopiles will be installed using the following process:

- Lift monopile into the pile gripper on the side of the installation vessel;
- Lift hammer onto monopile and drive monopile into seabed to required embedment depth;
- Lift hammer from monopile and remove pile gripper;
- Lift transition piece onto monopile; and
- Secure transition piece onto monopile using either grout or bolts.

3.6.4.9 The TP will either have a bolted or grouted connection to the MP. The grout used is an inert cement mix that is pumped into a specially designed space between the TP and the monopile. The grout will be pumped either from the installation vessel or a support vessel. This process is carefully controlled and monitored to ensure minimal grout is lost to the surrounding environment. The bolted solution will use bolts to connect the TP to the MP in a similar manner to that used to connect the turbine and the transition piece.

3.6.4.10 Up to four installation vessels may be used, with up to two piling and two drilling simultaneously. The details for the vessels and numbers of trips required can be found in Table 3.7 below. Monopile installation may take up to 30 months in total for turbines.

Table 3.7: Vessel and helicopter requirements for monopile, piled jacket, suction bucket jacket and mono suction bucket installation.

Vessel type	Maximum number of vessels	Maximum number of return trips per vessel type
Installation vessels	4	342
Support vessels	16	1,368
Transport vessels (barges)	10	171
Transport vessels (tugs)	30	513
Helicopter support		684

3.6.4.11 Seabed preparations for monopile installation are usually minimal. If preconstruction surveys show the presence of boulders or other seabed obstructions at foundation locations, these may be removed if the foundation cannot be re-sited to avoid the obstruction. The total Hornsea Three area requirements can be seen in Table 3.5.

Piling and drilling

3.6.4.12 The modelled (noise) piling scenario (see volume 4, annex 3.1: Subsea Noise Technical Report) for monopiles and jacket pin piles assumes a maximum 4 hr duration. Analysis of recent piling records at DONG Energy wind farms indicates that piling of monopiles typically average 2 hours or less for installation (including the slow start procedure), with timings slightly longer at the beginning of the construction phase and then reducing as experience is gained. Piling at substations has usually taken a little longer, typically averaging 3 hours or less, with the longer times probably due to shorter runs and hence less opportunity for building up experience at the site. Likewise, the number of positions where piling work exceeds four hours is typically a small percentage, around 5% or less; this exceedance will be due to breaks in the construction work caused by reasons such as particularly challenging ground conditions or break-down of equipment and therefore does not reflect an uninterrupted 4 hr start-finish hammer strike piling duration.

3.6.4.13 The maximum hammer energy for Hornsea Three is 5,000 kJ for monopiles (and for 2,500 kJ jacket pin piles). The rationale for a 5,000 kJ hammer is to maximise the opportunity to successfully drive all piles. Although a 5,000 kJ hammer is being requested, hammer energies will be significantly lower for the overwhelming majority of the time and the driving energy will be raised to 5,000 kJ only when absolutely necessary. To minimise fatigue loading on the piles, hammer energies are continuous set at the minimum required, which also reduces likelihood of breakdown of the equipment, hence will typically start low (15% soft start of 750 kJ) and gradually increase to the maximum required installation energy during the piling of the final meters, which is typically significantly less than the maximum consented hammer energy. A review of construction logs and a preliminary analysis of ground conditions at the site, Hornsea Three currently expect the average hammer energy across the entire construction programme to be less than 2,000 kJ and the maximum energy at each position (i.e. for the final few meters) to be on average less than 2,500 kJ. The larger hammer will not change this and indeed may allow these values to be reduced. Other reasons why larger hammers are required include the greater effectiveness at pile driving and greater reliability, since they are working far under their design rating for the majority of the time. Knowledge of the anticipated construction work will improve as additional geoscience survey campaigns are undertaken and corresponding design work is completed

3.6.4.14 If percussive piling installation is not possible due to the presence of rock or hard soils, the material inside the monopile may be drilled out before the monopile is driven to the required depth. This can either be done in advance of the driving or if the piling rate slows significantly during piling, known as refusal. If drilling is required, spoil arising from the drilling will be disposed of adjacent to the foundation location above the sea surface. Total wind farm spoil volume is given in Table 3.5.

3.6.4.15 It may also be possible that the piles are installed via another novel method such as vibropiling, where the pile is embedded via vibration rather than hammering or drilling. If any such methods were employed, it would be ensured that the noise emissions were within the envelope consented for hammering.

Piled jacket foundations

Design

3.6.4.16 Piled jacket foundations are formed of a steel lattice construction (comprising tubular steel members and welded joints) secured to the seabed by hollow steel pin piles attached to the jacket feet. The piles rely on the frictional and end bearing properties of the seabed for support. Unlike monopiles, there is no separate TP. The TP and ancillary structure is fabricated as an integrated part of the jacket. Pin piles will typically be narrower than monopiles.

3.6.4.17 The Maximum design scenario for jacket foundations with pin piles is shown in Table 3.8.

Table 3.8: Maximum design scenario: jacket foundation with pin piles.

Parameter	Maximum design scenario
Number of legs per turbine	4
Separation of adjacent legs at seabed level (m)	40
Separation of adjacent legs at LAT (m)	25
Height of platform above LAT (m)	40
Leg diameter (m)	4.6
Pin pile diameter (m)	4
Embedment depth (below seabed) (m)	55
Hammer energy (kJ)	2,500

Installation

3.6.4.18 The installation of piled jackets is similar to that of monopiles, with the structures transported to site by installation vessels or barges and lowered onto the seabed by the installation vessel.

3.6.4.19 The pin piles can be installed either before or after the jacket is lowered to the seabed. If before, a piling template will be placed on the seabed to guide the pile locations. This is usually a welded steel structure. The piles will then be installed through the template, and the jacket affixed to the piles after it has been lowered into position, either welded or swaged. If piles are installed after the jacket is lowered to the seabed, the piles will be installed through the jacket feet at the seabed, or through the legs of the jacket from the top of the structure. As the there is no separate TP, there is no requirement for installing an additional structure offshore.

3.6.4.20 The pin piles are driven, drilled or vibrated into the seabed, in a similar way to monopiles. However as pin piles are smaller, the maximum hammer energy to be used would be 2,500 kJ. Further detail on piling duration and hammer energies is given in paragraphs 3.6.4.12 and 3.6.4.13. . There would be no more than two piles being driven simultaneously, and eight piles being drilled simultaneously across the Hornsea Three array area. The maximum duration for turbine foundation installation across the Hornsea Three array area would be 30 months.

3.6.4.21 The vessel movements for the installation would be as for monopile foundations, as described in Table 3.7.

3.6.4.22 The seabed preparation would be as for the monopile foundations (paragraph 3.6.4.11). The maximum design scenario can be seen in Table 3.5.

Suction bucket jacket foundations

Design

3.6.4.23 Suction bucket jacket foundations are formed with a steel lattice construction (comprising tubular steel members and welded joints) fixed to the seabed by suction buckets installed below each leg of the jacket. The suction buckets are typically hollow steel cylinders, capped at the upper end, which are fitted in a horizontal position underneath the legs of the jacket structure. They do not require a hammer or drill for installation. Unlike monopiles, but similarly to piled jacket foundations, there is no separate TP. The TP and ancillary structure is fabricated as an integrated part of the jacket structure and is not installed separately offshore. An example of a suction bucket jacket is shown in Figure 3.8.

3.6.4.24 The Maximum design scenario for jacket foundations with suction buckets is shown in Table 3.9.

Table 3.9: Maximum design scenario: jacket foundation with suction buckets.

Parameter	Maximum design scenario
Number of legs per turbine	4
Suction bucket diameter (m)	20
Suction bucket penetration (m)	20
Suction bucket height above seabed (m)	5
Separation of adjacent legs at seabed level (m)	40
Separation of adjacent legs at LAT (m)	25
Height of platform above LAT (m)	40

Figure 3.8: A jacket foundation with suction buckets being installed at the Borkum Riffgrund One offshore wind farm.

Installation

3.6.4.25 Once at site, the jacket foundation will be lifted by the installation vessel using a crane, and lowered towards the seabed in a controlled manner (see Figure 3.8). When the steel caisson reaches the seabed, a pipe running up through the stem above each caisson will begin to suck water out of each bucket. The buckets are pressed down into the seabed by the resulting suction force. When the bucket has penetrated the seabed to the desired depth, the pump is turned off. A thin layer of grout is then injected under the bucket to fill the air gap and ensure contact between the soil within the bucket, and the top of the bucket itself. As the there is no separate TP, there is no requirement for installing an additional structure offshore.

3.6.4.26 The vessel movements for the installation would be as for the monopile foundations, as described in Table 3.7.

3.6.4.27 As well as the boulder and obstruction removal that is described in the monopile section (paragraph 3.6.4.11), the suction bucket jackets may also require some seabed levelling, to ensure that all of the buckets for each structure can be placed at the same level, and that there is level ground beneath them to form a sealed chamber within the bucket once the foundation has been lowered to the seabed. The seabed levelling would likely be carried out by a dredging vessel using a suction hopper, and depositing the dredged material adjacent to the foundation location at site. The total Hornsea Three area and spoil requirements can be seen in Table 3.5. A Dredging and Disposal: Site Characterisation is presented in volume 4, annex 3.2.

Mono suction bucket foundations

Design

3.6.4.28 A mono suction bucket consists of a single suction bucket supporting a single steel or concrete structure, which supports the wind turbine. As with the jacket structures and suction bucket foundations, this foundation type does not require a TP to be installed offshore. The Maximum design scenario for this foundation type can be seen in Table 3.10 below. As the there is no separate TP, there is no requirement for installing an additional structure offshore.

Table 3.10: Maximum design scenario: mono suction bucket.

Parameter	Maximum design scenario
Suction bucket diameter (m)	40
Suction bucket penetration depth (m)	20
Suction bucket height above seabed (m)	10

Installation

3.6.4.29 The installation method is similar to that described for the suction bucket jackets in section 3.6.4.25 except only a single bucket needs to be installed in the seabed.

3.6.4.30 The vessel movements for the installation would be as for the monopile, as described in Table 3.7.

3.6.4.31 The seabed preparation would be as described for the suction bucket jacket. The total Hornsea Three area and spoil requirements can be seen in Table 3.5.

Gravity base foundations

Design

3.6.4.32 Gravity base foundations are heavy steel, concrete, or steel and concrete structures, sometimes including additional ballast that sit on the seabed to support the turbine tower (Figure 3.9). Gravity bases vary in shape, but are significantly wider at the base (at seabed level) to provide support and stability to the structure. They then generally taper to a smaller width at or below seabed level.

3.6.4.33 The Maximum design scenario for gravity base foundations is shown in Table 3.11.

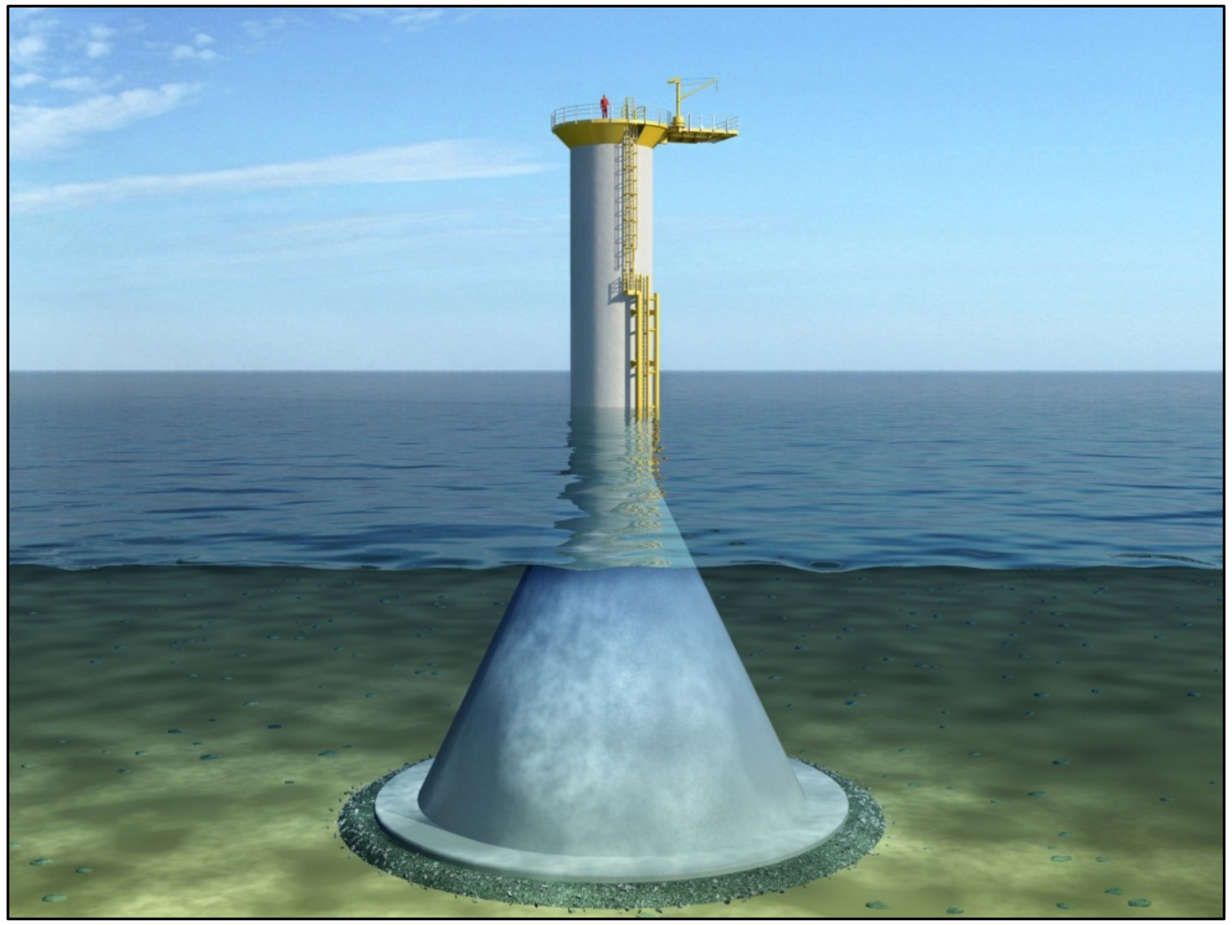


Figure 3.9: A gravity base foundation.

Table 3.11: Design envelope: gravity base foundation.

Parameter	Maximum design scenario
External diameter at seabed (excluding scour protection) (m)	53
External diameter at LAT (m)	15
Seabed preparation diameter (m)	61
Scour protection diameter (m)	93

Installation

3.6.4.34 A gravity base does not require piling or drilling to remain in place. They can either be brought to site on barges or installation vessels as for the other foundation types, or alternatively they can be floated to site. This would be done by designing the structures to be buoyant, and towing them to site using tugs and support vessels. The foundations would then be lowered to the seabed in a controlled manner either by pumping in water, or installation of ballast (or both).

3.6.4.35 The vessel requirements for gravity base foundations would be as described in Table 3.12.

Table 3.12: Vessel requirements for gravity base foundations for turbines if floated to site.

Vessel type	Maximum number of vessels	Maximum number of return trips per vessel type
Installation Vessels	3	342
Support Vessels	13	1710
Dredging Vessels	12	1368
Tug Vessels	4	1368

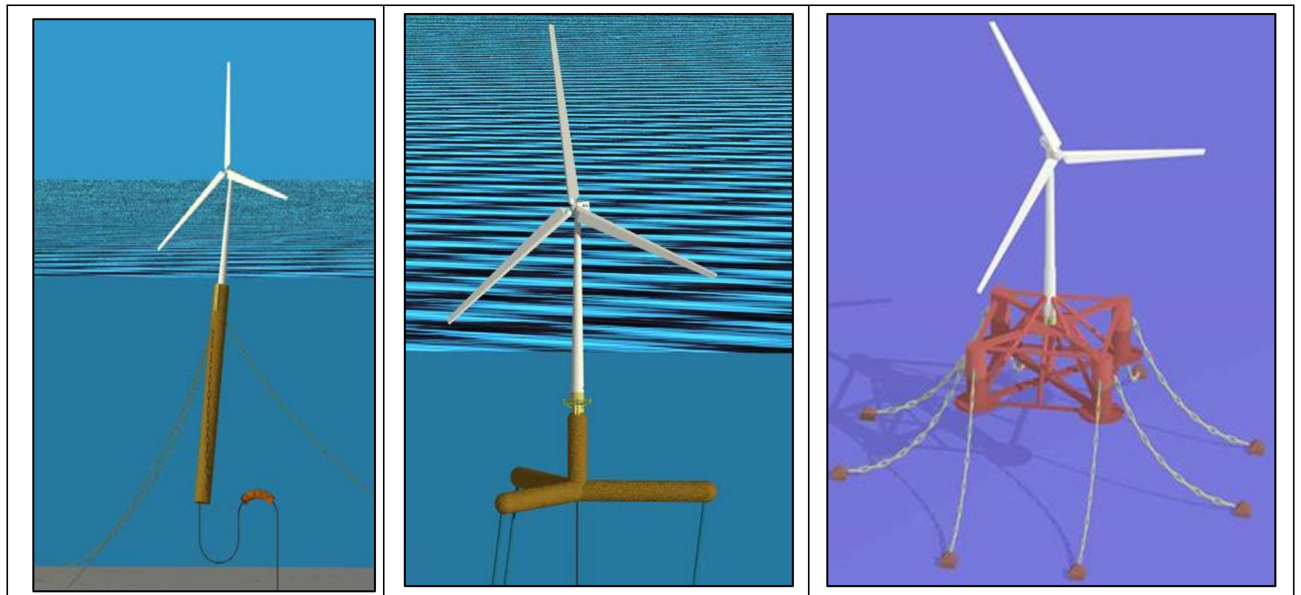
3.6.4.36 Gravity base foundations need to be placed in pre-prepared areas of seabed. Seabed preparation would involve levelling and dredging of the soft mobile sediments as required, as well as any boulder and obstruction removal. It is likely that dredging would be required if using the gravity base foundations. If dredging is required it would be carried out by dredging vessels using suction hoppers or similar, and the spoil would be deposited on site adjacent to the turbine locations.

3.6.4.37 The seabed preparation would be as described for the suction bucket jacket. The total Hornsea Three area and spoil requirements can be seen in Table 3.5.

Floating foundations

Design

3.6.4.38 Floating foundations can consist of a range of structure types, typically classed as spar buoys, tensioned-leg platforms or semi-submersibles (see Figure 3.10). The classification of floating foundations depends on how stability is achieved; by ballast at the base of the spar, by tension in the mooring lines or by a wide structure at the water surface. Typically, the structure will consist of either a single slender vertical cylindrical structure, called a spar buoy, or a shallower and more complex structure consisting of various tubular and plate elements, called tensioned-leg platforms or a semi-submersible platform.



Spar class (Ballast stabilised) | Tensioned-leg platform class (Moorings stabilised) | Semi-submersible class (Buoyancy and moorings stabilised)

Figure 3.10: Examples of floating foundations.

3.6.4.39 The foundations are typically fabricated from steel and/or concrete and are held in place by mooring lines connected to anchors in the seabed. The anchors could be piles (as described for piled jackets in section 3.6.4.16), suction buckets, gravity structures or drag anchors. The maximum seabed footprint for floating foundations will not exceed that of gravity base foundations as described in section 3.6.4.32.

3.6.4.40 The Maximum design scenario for floating foundations is shown in Table 3.13.

Table 3.13: Maximum design scenario: floating foundation.

Parameter	Maximum design scenario
Foundation surface dimension (m)	75
Depth of structure (m)	50
Number of mooring lines and anchors (per turbine)	12
Mooring cable radius (m)	1,000
Maximum anchor height (above seabed) (m)	7.5

Installation

3.6.4.41 The structures will either be floated into place from harbour or brought to site on suitable installation vessels and lifted into the water. The anchors will be installed using a range of methods dependent on the anchor type, including piling and drilling if piles are used (as described in section 3.6.4.12), or suction, and placement if gravity, suction or drag anchors are used (the impacts of these techniques would sit inside the envelope outlined in section 3.2). The installation of the anchors is likely to be carried out by a separate vessel.

3.6.4.42 The vessel requirements for floating foundations will not exceed those described in Table 3.12.

3.6.4.43 It is unlikely that significant seabed preparation would be required for floating foundations. However, some dredging and levelling may be required if gravity or suction anchors are used, as well as any boulder and obstruction removal as required. The total wind farm area and spoil requirements can be seen in Table 3.5.

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

3.6.4.45 The amount of scour protection required will vary for the different foundation types being considered for Hornsea Three. Flexibility in scour protection choice (rock armouring and use of mattresses) is required to ensure that anticipated changes in available technology and project economics can be accommodated within the Hornsea Three design. The final choice and detailed design of a scour protection solution for the wind farm will be made after detailed design of the foundation structure, taking into account a range of aspects including geotechnical data, meteorological and oceanographic data, water depth, foundation type, maintenance strategy and cost.

3.6.4.46 The maximum diameter of the rocks used would be 1 m and the maximum thickness of scour protection layer would be 2 m. The total Hornsea Three volume of material can be seen in Table 3.5.

Foundation types for offshore substations and offshore accommodation platforms

3.6.4.47 Although all the foundation options available for turbines (excluding floating foundations) may also be used for offshore substations (OSS) and offshore accommodation platforms (OAP), there are some foundation designs that could be used for OSS and OAP but will not be used for supporting turbines. The descriptions of these foundations are outlined below.

<u>OSS piled jacket</u>

3.6.4.48 This foundation type is a larger variant of the piled jacket option to be used for turbines as described in section 3.6.4.16. These foundations may also require the use of mud-mats, which are flat plates attached to the bottom of the jacket legs to support the foundation structure before piles are installed (if piles are installed after the jacket). The parameters for the OSS piled jacket foundation can be seen in Table 3.14 below. All other parameters are as described in section 3.6.4.16.

Table 3.14: Maximum design scenario: OSS piled jacket.

Parameter	Maximum design scenario
Number of legs per jacket	6
Piles per leg	4
Separation of adjacent legs at seabed level (m)	70
Separation of adjacent legs at LAT (m)	70
Height of platform above LAT (m)	40
Leg diameter (m)	5
Pin pile diameter (m)	4
Pile height above seabed (m)	20
Mud-mats length and width [m]	10
Embedment depth (below seabed) (m)	70
Hammer energy (kJ)	2,500

OSS suction bucket jacket

3.6.4.49 This foundation type is a larger variant of the suction bucket jacket option to be used for turbines, as described in section 3.6.4.23. The parameters for the OSS suction bucket jacket foundation can be seen in Table 3.15 below. All other parameters are as described in section 3.6.4.23.

Table 3.15: Maximum design scenario: OSS suction bucket jacket.

Parameter	Maximum design scenario
Number of legs per platform	6
Suction bucket diameter (m)	25
Suction bucket penetration (m)	25
Separation of adjacent legs at seabed level (m)	70
Separation of adjacent legs at sea surface (m)	70
Height of platform above LAT (m)	40

Box type gravity base

3.6.4.50 This foundation type is a variant of the gravity base foundation, as described in section 3.6.4.32, however rather than having a circular base to support a single tower, this type of foundation has a square base that supports the steel or concrete supporting structure for the substation topsides. The parameters for the box type gravity base foundation can be seen in Table 3.16 below. All other parameters are the same as for the gravity base as described in section 3.6.4.32. This foundation type will not be used for OAPs.

Table 3.16: Maximum design scenario: Box type gravity base.

Parameter	Maximum design scenario
Length and width at seabed level (m)	75
Length & and width at LAT (m)	75
Seabed preparation buffer around base (m)	50
Seabed preparation buffer below base (m)	-1
Length & Width of seabed preparation area (m)	175

Foundation types for offshore HVDC converter stations.

3.6.4.51 Although all the foundation options available for turbines (excluding floating foundations), OSS and OAP may also be used for offshore HVDC converter substations, there are some foundation designs that could be used for offshore HVDC converter substations but are not intended to be used for supporting other offshore infrastructure. The descriptions of these foundations is outlined below.

Converter piled jacket

3.6.4.52 This foundation type is a larger variant of the piled jacket option to be used for turbines, as described in section 3.6.4.16. The offshore HVDC converter stations could each be supported by four jacket structures, or a single larger jacket. The parameters for the converter piled jacket can be seen in Table 3.17 below. All other parameters are as described in section 3.6.4.16.

Table 3.17: Maximum design scenario: Converter piled jacket.

Parameter	Maximum design scenario
Number of jackets per platform	4
Number of legs per platform	18
Piles per leg	4
Separation of adjacent legs at seabed level (m)	100
Separation of adjacent legs at LAT (m)	100
Pin pile diameter (m)	3.5
Pile penetration (m)	70
Mud-mats length and width (m)	20
Hammer energy (kJ)	2,500

Converter suction bucket jacket

3.6.4.53 This foundation type is a larger variant of the suction bucket jacket option to be used for turbines, as described in section 3.6.4.23. The parameters for the converter suction bucket jacket can be seen in Table 3.18 below. All other parameters are as described in section 3.6.4.23.

Table 3.18: Maximum design scenario: converter suction bucket jacket.

Parameter	Maximum design scenario
Number of jackets per platform	4
Number of legs (per jacket)	6
Suction bucket diameter (m)	20
Suction bucket penetration (m)	30

Pontoon gravity base – type 1

3.6.4.54 This foundation type is a variant of the gravity base foundation, as described in section 3.6.4.32, however rather than having a circular base to support a single tower, this type of foundation has up to three rectangular pontoons that support the steel or concrete supporting structure for the substation topside. The parameters for the pontoon gravity base – type 1 can be seen in Table 3.19 below. An example of this design can be seen in Figure 3.11. All other parameters are the same as for the gravity base as described in section 3.6.4.32.

Table 3.19: Maximum design scenario: pontoon gravity base – type 1.

Parameter	Maximum design scenario
Number of pontoons per platform	3
Pontoon length (m)	170
Pontoon width (m)	35
Pontoon spacing (m)	36
Pontoon base width (m)	90

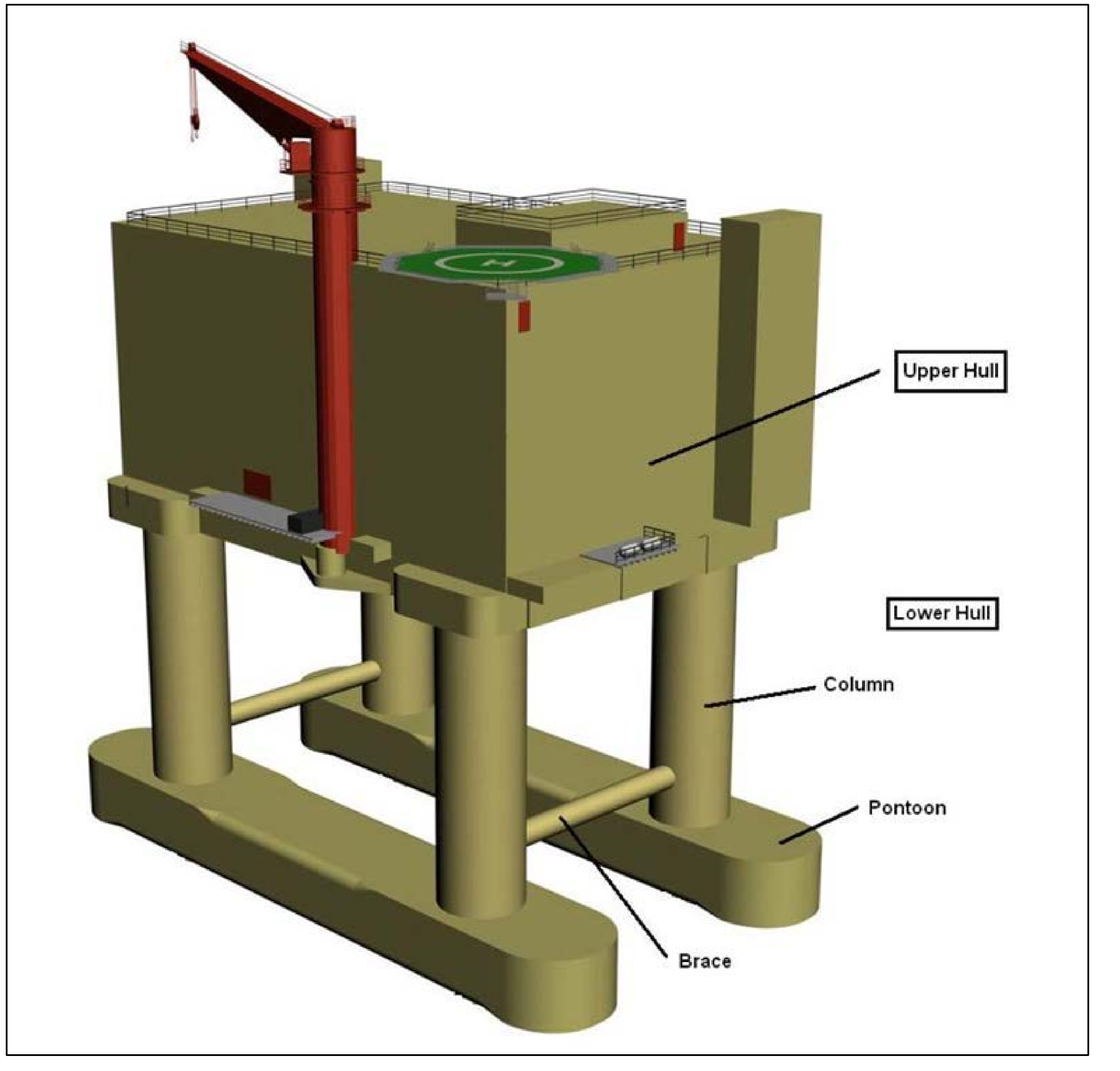


Figure 3.11: An example of a converter substation design supported by a Pontoon Gravity Base – pontoon gravity base – type 1[1].

[1] Note that this example has two pontoons, rather than the maximum three.

Pontoon gravity base – type 2

3.6.4.55 This foundation type is a variant of the gravity base foundation, as described in section 3.6.4.32, however rather than having a circular base to support a single tower, this type of foundation has a pontoon, arranged in a rectangle around an open centre, that supports the steel or concrete supporting structure for the substation topside. The parameters for the pontoon gravity base - type 2 can be seen in Table 3.20 below. All other parameters are the same as for the gravity base as described in section 3.6.4.32.

Table 3.20: Maximum design scenario: pontoon gravity base – type 2.

Parameter	Maximum design scenario
Number of pontoons per platform	1
Pontoon length (m)	120
Pontoon width (m)	35

Scour protection for foundations

3.6.4.56 Scour protection is designed to prevent foundation structures for turbines, substations and offshore accommodation platforms, being undermined by hydrodynamic and sedimentary processes, resulting in seabed erosion and subsequent scour hole formation. The shape of the foundation structure is an important parameter influencing the potential depth of scour hole formation. Scour around foundations is typically mitigated by the use of scour protection measures. Several types of scour protection exist, including mattress protection, sand bags, stone bags and artificial seaweeds. However, the placement of large quantities of crushed rock around the base of the foundation structure is the most frequently used solution ('rock placement').

3.6.5 Array cables

3.6.5.1 Cables carrying the electrical current produced by the turbines will link the turbines to an offshore substations. A small number of turbines will typically be grouped together on the same cable 'string' connecting those turbines to the substation, and multiple cable 'strings' will connect back to each offshore substation.

3.6.5.2 It is likely the array cable system will use HVAC technology, but it is also possible that the system will consist of [a more novel technology] an alternative option such as a HVDC or low frequency HVAC array cable system.

Design

3.6.5.3 The array cables will consist of a number of conductor cores, usually made from copper or aluminium surrounded by layers of insulating material, as well as material to armour the cable for protection from external damage, and material to keep the cable watertight.

3.6.5.4 The Maximum design scenario for array cables is shown in Table 3.21 below.

Table 3.21: Maximum design scenario: array cables.

Parameter	Maximum design scenario
Cable diameter (mm)	200
Total length of cable (km)	850
Voltage (kV)	170

Installation

3.6.5.5 The 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 (CBRA) taking into account ground conditions as well as external aggressors to the cable such as trawling and vessel anchors. This depth will likely vary across the Hornsea Three array area. Possible installation methods include jetting, vertical injection, cutting and ploughing whereby the seabed is opened and the cable laid within the trench simultaneously using a tool towed behind the installation vessel. Alternatively, a number of these operations such as jetting, cutting or Mass Flow Excavation (MFE) may occur post cable lay. It may also be necessary to install the cable by pre-trenching or rock cutting whereby a trench is opened in one operation and then the cable laid subsequently from another vessel. Hornsea Three may also need to dredge the cable route prior to installation in order to level sandwaves that may hinder installation. Figure 3.12 shows an array cable being installed.

3.6.5.6 If the array cables must cross third party infrastructure such as existing cables both the third party asset and the installed cable must be protected. This protection would usually consist of a rock berm on the existing cable (separation layer), as well as a second rock berm on the cable installed for Hornsea Three (protection layer). The detailed design of the crossing would be decided in a crossing agreement developed by both parties. The methodology for array cable crossings would be the same as for export cable crossings, paragraph 3.6.9.8 describes this process in more detail.

3.6.5.7 The maximum design scenario for array cable installation can be seen in Table 3.22. Greater detail on how the total numbers have been calculated are shown in Table 3.23.

Figure 3.12: Array cable installation at the Gode Wind offshore wind farm.

Table 3.22: Maximum design scenario: array cable installation.

Parameter	Maximum design scenario
Installation methodology	Trenching, dredging, jetting, ploughing, mass flow excavation, vertical injection, rock cutting
Burial depth	Typically 1-2 m. Dependent on CBRA [a]
Width of seabed affected by installation per cable (m)	10
Width of seabed affected by sandwave clearance (where required) per cables (m)	30
Total seabed disturbed (km^2)	8.5
Seabed disturbance (m^2)	8,500,000
Burial spoil: jetting (m^3) [b]	1,878,500
Burial spoil: ploughing/mass flow excavation (m^3) [b]	5,100,000
Duration: per cable (days)	3
Duration: total (months)	30

a Typically the cable will be buried between 1 - 2m. A Cable Burial Risk Assessment (CBRA) will inform cable burial depth, dependent on ground conditions as well as external risks. This assessment will be undertaken post-consent.

b These values are derived in Table 3.23 below.

Table 3.23: Maximum design scenario: array cable installation – cable burial.

Parameter	Maximum design scenario
Jetted depth (95% of full length) (m) [a]	3
Jetted width (95% of full length) (m) [a]	0.6
Jetted depth (5% of full length) (m) [a]	10
Jetted width (5% of full length) (m) [a]	1
Burial spoil: jetting (m^3)	1,878,500
Ploughing/mass flow excavation depth (m)	2
Ploughing/mass flow excavation width (m)	6
Burial spoil: ploughing/mass flow excavation (m^3)	5,100,000

a Final burial depth will be defined by a CBRA, however in order to carry out an assessment of the environmental impact these values have been assumed as a worst case.

3.6.5.8 Table 3.24 shows the details for the rock placement required for array cables and Table 3.25 shows the envelope for vessel movements associated with array cable installation.

Sandwave clearance

3.6.5.9 In some areas within the offshore array (and in the Hornsea Three offshore cable corridor for the export cables) existing sandwaves and similar bedforms may be required to be removed before cables are installed. This is done for two reasons. Firstly, many of the cable installation tools require a relatively flat seabed surface in order to work properly. It may not be possible to install the cable up or down a slope over a certain angle, as well as if the installation tool is working on a camber. Secondly, the cable must be buried to a depth where it may be expected to stay buried for the duration of Hornsea Three's project lifetime. Sandwaves are generally mobile in nature therefore the cable must be buried beneath the level where natural sandwave movement would uncover it. Sometimes this can only be done by removing the mobile sediments before installation takes place.

3.6.5.10 If required, this sandwave clearance would require dredging using a suction dredger or similar. Any sediment removed would be disposed of within local sandwave field.

Table 3.24: Maximum design scenario: array cable installation – rock placement.

Parameter	Maximum design scenario
Height of rock dumping (m)	2
Width of rock dumping (m)	7
Percentage of route requiring protection	10
Replenishment during operations (% of construction total)	25
Cable rock protection: maximum rock size (m)	1
Rock protection area (m^2)	595,000
Rock protection volume (m^3)	850,000
Number of crossings (estimate)	12
Cable/pipe crossings: pre-lay rock berm area (m^2)	7,200
Cable/pipe crossings: pre-lay rock berm volume (m^3)	7,500
Cable/pipe crossings: post-lay rock berm area (m^2)	33,600
Cable/pipe crossings: post-lay rock berm volume (m^3)	24,000
Sandwave clearance volume (m^3)	115,106

Table 3.25: Maximum design scenario: array cable installation vessel and helicopter requirements.

Parameter	Maximum design scenario
Main laying vessels	3
Main burial vessels	3
Support vessels: crew boats or SOVs	4
Support vessels: service vessel for pre-rigging of towers	2
Support vessels: diver vessels	2
Support vessels: vessels for PLGR	2
Support vessels: dredging vessels	2
Main laying vessels (return trips)	357
Main burial vessels (return trips)	357
Support vessels (return trips)	2,142
Helicopter support – construction (return trips)	684

3.6.6 Offshore accommodation platforms

3.6.6.1 Hornsea Three may construct up to three offshore accommodation platforms to allow up to 150 operations staff to be housed at the Hornsea Three array area for a number of weeks at a time, and to allow spares and tools to be stored at the Hornsea Three array area. This aims to reduce trips to the Hornsea Three array area and time spent in transit, in order to decrease down time for faults and repairs. The offshore accommodation platforms would be accessed by vessel and/or helicopter, and may have associated captive vessels to access the turbines and substations. An example of an offshore accommodation platform can be seen in Figure 3.13. All offshore accommodation platforms would be located in the Hornsea Three array area.

Figure 3.13: Offshore accommodation platform (right) at the Horns Rev 2 offshore wind farm, sited next to an offshore substation (left)[2].

[2] Note - the offshore accommodation platform is supported by a monopile foundation, and the offshore substation by a jacket foundation.

Design

3.6.6.2 The Maximum design scenario for the offshore accommodation platforms can be seen in Table 3.26 and Table 3.27 below. The offshore accommodation platforms may also be co-sited with offshore substations, including bridge access between the two platforms. The offshore accommodation platforms would use the same substructure and foundation concepts as the turbines and offshore substations (excluding box type gravity base foundations). Hornsea Three requires flexibility in location and foundation choice to ensure that anticipated changes in available technology and project economics can be accommodated within the Hornsea Three design, however the accommodation platforms will be located within the Hornsea Three array area.

Installation

3.6.6.3 The installation procedure would be as described for the offshore transformer substations in paragraphs 3.6.8.11.

Table 3.26: Maximum design scenario for offshore accommodation platforms.

Parameter	Maximum design scenario
Number	3
Length and width (m)	60
Main structure height above LAT (m)	60
Structure height max above LAT (m)	64
Foundation type	As for turbines or offshore substations (excluding box type gravity base).
Installation	As for offshore substations in section 3.6.8

Table 3.27: Maximum design scenario for offshore accommodation platforms – chemicals.

Parameter	Maximum design scenario
Chemicals: coolant (per platform) (l)	10,000
Chemicals: hydraulic oil (per platform) (l)	10,000
Chemicals: lubricates (per platform) (kg)	3,500
Chemicals: heli fuel (across wind farm) (l)	255,000
Chemicals: vessel fuel (per platform) (l)	210,000

3.6.7 Transmission system

3.6.7.1 The wind farm transmission system is used to transport the power produced at the turbines and delivered by the array cables, to the UK National Grid. The system transforms the Medium Voltage (MV) power produced at the turbines to HV at the offshore transformer substations (located in the Hornsea Three array area), and transports this via export cables and a number of other offshore and onshore components (see paragraph 3.6.7.4). The transmission system is usually designed, paid for and constructed by the wind farm developer (DONG Energy in the case of Hornsea Three), but must be purchased by an Offshore Transmission Operator (OFTO) after the wind farm is constructed in a transaction overseen by the Office of Gas and Electricity Markets (Ofgem). It is also possible that the transmission asset may be designed, procured and installed by the OFTO, however the design and installation parameters would still be consented through this application.

Project capacity

3.6.7.2 The point at which the energy produced by the wind farm is metered is at the offshore substation (currently MV side of the transformer), therefore all wind farm capacities defined through the consenting process will be in reference to the capacity at the MV side of the offshore substation. Hornsea Three has a planned maximum capacity of 2.4 GW. The total capacity of the turbines themselves may exceed 2.4 GW in order to compensate for electrical losses in the array cables, as well as for turbines shut down for maintenance. However the total number and dimensions of turbines would not exceed that stated within this chapter. Hornsea Three may be split into up to three phases (see section 3.8 for details). The phases may be constructed either separately or together (see section 3.8 for further details).

HVAC/HVDC transmission systems

3.6.7.3 There are a range of transmission system designs that can be used to transport the power from the Hornsea Three array area to the UK National Grid. These fall under two primary transmission types defined by how the current is delivered to the export cables; HVAC or HVDC. Both transmission types have a range of relative benefits and drawbacks. Offshore wind farms have traditionally used HVAC connections; however, HVDC connections become more technically and/or economically viable in the context of far from shore projects and are used on a number of projects in Germany. Hornsea Three requires flexibility in transmission system choice to ensure that anticipated changes in available technology and project economics can be accommodated within the Hornsea Three design, and will make a decision on which transmission type to use during the detailed design phase (post consent).

3.6.7.4 An overview of the differences between the component requirements between two technologies are outlined in Table 3.28.

Table 3.28: Infrastructure required for High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC) systems.

Component	HVAC	HVDC	Comment
Offshore transformer substation	Y	M	HVDC: may be combined with converter substation
Offshore interconnector cable	M	M	Interconnector cables may be required between offshore substations.
Offshore HVDC converter substation	N	Y	-
Offshore export cable	Y	Y	-
Offshore HVAC booster station(s)	M	N	HVAC: onshore and/or offshore HVAC booster station required.
Onshore HVAC booster station	M	N	
Onshore export cable	Y	Y	-
Onshore HVDC converter/HVAC substation	Y	Y	HVDC systems require larger onshore converter substations for conversion to HVAC.
Grid connection export cable	Y	Y	-
Table Key	*Required (Y)*	*May be required (M)*	*Not required (N)*

Circuit description

3.6.7.5 A circuit is an electrical system that allows the flow of electrons from one location to another. Typical HVAC transmission systems are three phase designs and require three conductors per electrical circuit to transport the power. Offshore these three conductors are usually combined into a single cable. Onshore these three conductors are usually housed within one cable per conductor (so three cables per circuit) (Table 3.29).

3.6.7.6 Typical HVDC transmission systems are Bi-Pole designs and require two conductors per circuit to transport the power. Offshore these are generally housed in separate cables but these cables may be installed together. Onshore these conductors are housed in separate cables (Table 3.29).

Table 3.29: Cables required per circuit.[3]

	HVAC	HVDC
Offshore cables/circuit	1	2 [a]
Onshore cables/circuit	3	2

a Two HVDC offshore cables may be bundled together and installed simultaneously.

3.6.8 Offshore substations

3.6.8.1 Offshore substations are offshore structures housing electrical equipment to provide a range of functions, such as changing the voltage (transformer substations), current type (converter substations) or power factor of the power (Offshore HVAC booster stations,). Each of the different offshore substation types is detailed below. All offshore substations will be marked, as with the turbines, for aviation and navigation purposes (see paragraph 3.6.8.26) . The exact substation locations will be determined during the wind farm design phase (typically post consent), taking account of ground conditions and the most efficient cable routing amongst other considerations. Offshore substations will not be manned but once functional will be subject to periodic operational and maintenance visits by staff by helicopter, by vessel or from a nearby accommodation platform.

3.6.8.2 Hornsea Three requires flexibility in location and foundation choice of offshore transformer substation (see 3.6.4) to ensure that anticipated changes in available technology and project economics can be accommodated within the Hornsea Three design.

3.6.8.3 A description of the offshore substations is provided below.

Offshore transformer substations

3.6.8.4 Offshore transformer substations are required in HVAC transmission systems and may be required in HVDC transmission systems, dependent on the system design.

3.6.8.5 One or more offshore transformer substations will collect the electricity generated by the operational turbines via the array cables. The voltage will be "stepped up" by transformers on the substation before transmission to the onshore HVDC converter/HVAC substation by export cables; this will be via the offshore HVAC converter substation in the case of the HVDC transmission option, or the offshore and/or onshore HVAC booster station(s) in the case of the HVAC transmission option.

[3] Irrespective of the electrical system chosen (AC or DC) the total number of export cables will not exceed 6 offshore and 18 onshore.

3.6.8.6 All offshore transformer substations would be located in the Hornsea Three array area.

Design

3.6.8.7 The HV equipment on the offshore transformer substations is expected to be rated between 220 kV and 400 kV. The substation unit is pre-fabricated in the form of a multi-layered cube and will be mounted on a foundation (Figure 3.14) some distance above the sea surface.

3.6.8.8 For some HVDC transmission system designs, the equipment required in the offshore transformer substation will be incorporated into the offshore HVDC converter substation. It may also be beneficial to co-locate the offshore transformer substations with turbines so that a substation and a turbine may share a single foundation structure. It may also be beneficial to site multiple differing substations, or substations and offshore accommodation platforms, next to each other so that access can be gained from one to the other. In this case a bridge link may be constructed at deck level, with a length of up to 100 m

3.6.8.9 Up to 12 separate offshore transformer substations are required. All offshore transformer substations will be located within the Hornsea Three array area.

3.6.8.10 The Maximum design scenario for this can be seen in Table 3.30 and a schematic can be seen in Figure 3.15.

Figure 3.14: Offshore substations at Gode Wind offshore wind farm.

Table 3.30: Maximum design scenario for offshore transformer substations.

Parameter	Maximum design scenario
Number of offshore transformer substations	12
Topside – main structure length and width (m)	90
Topside – ancillary structure length and width (m)	100
Topside – height (excluding helideck or lightning protection) (LAT) (m)	70
Height of lightning protection & ancillary structures (LAT) (m)	90
Topside - area (m^2)	8,100
Topside (inc. ancillaries) area (m^2)	10,000
Transformer oil - per substation (kg)	200,000
Diesel Fuel - per substation (l)	50,000
SF6 – per substation (kg)	1,500
Batteries (lead acid gel) – per substation (kg)	6,000

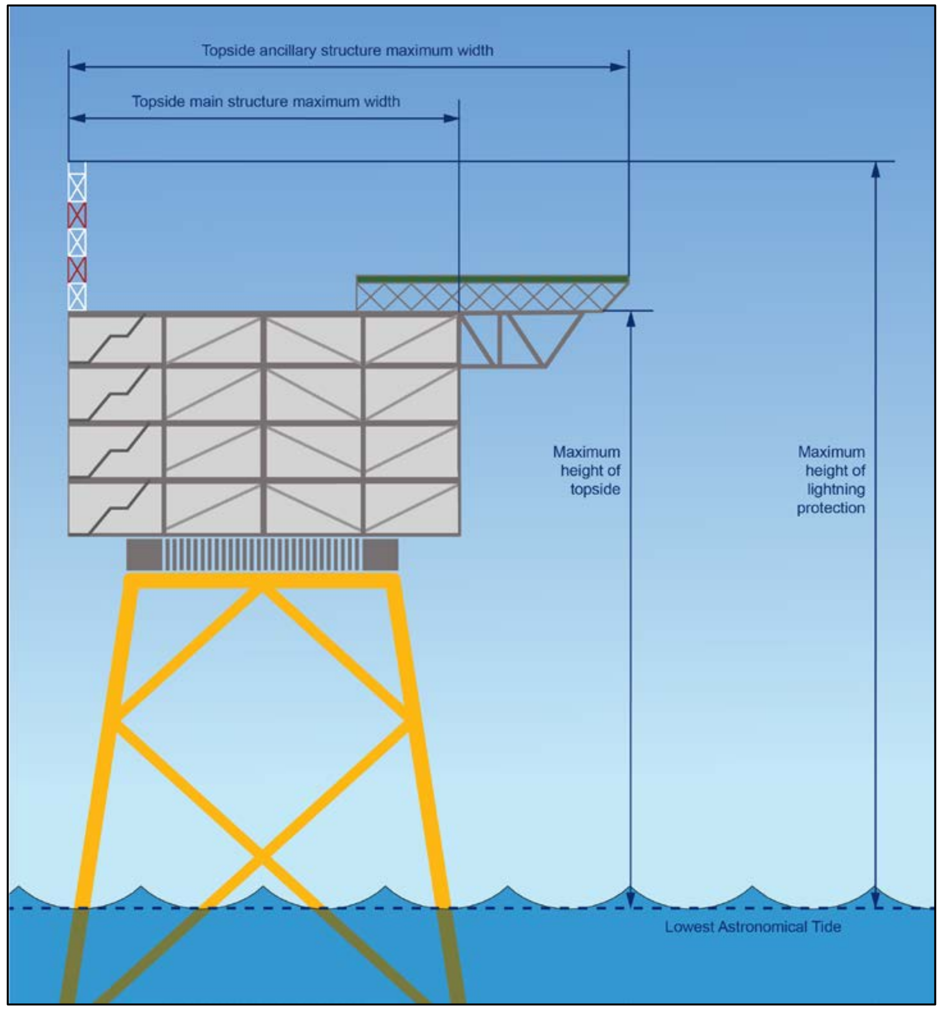


Figure 3.15: Schematic of an offshore transformer substation.

Installation

3.6.8.11 Offshore transformer stations are generally installed in two phases, the first phase will be to install the foundation for the structure using an installation vessel as described in section 3.6.4, secondly an installation vessel (same or different from the one installing the foundation) will be used to lift the topside from a transport vessel/barge, onto the pre-installed foundation structure. The foundation and topside may be transported on the same transport vessel/barge, or separately. The foundation may also be transported by the installation vessel. The vessel requirements for this process can be seen in Table 3.31. These values cover all offshore substations and accommodation platforms, not just offshore transformer substations.

Table 3.31: Maximum design scenario for offshore substations installation.

Parameter	Maximum design scenario
Primary installation vessels	2
Support vessels	12
Transport vessels/barges	4
Duration (per substation) (months)	2
Installation vessels (all offshore substations and accommodation platforms) (return trips)	38
Support vessels (all offshore substations and accommodation platforms) (return trips)	228
Transport vessels (all offshore substations and accommodation platforms) (return trips)	38
Helicopter support – construction (all offshore substations and accommodation platforms)	532

Offshore HVDC converter substations

3.6.8.12 Offshore HVDC converter substations are required in HVDC transmission systems only; they are not required in HVAC transmission systems. Offshore HVDC converter substations convert the three-phase AC power generated at the turbines into DC power. This is then transmitted to the onshore HVDC converter/HVAC substation via the export cables.

Design

3.6.8.13 As for the offshore transformer substations, the offshore HVDC converter substation unit is pre-fabricated in the form of a multi-layered cube. The offshore HVDC converter substation is expected to be larger than the offshore transformer substations, due to the differing power electronics it would contain. The structure will be mounted on a foundation some distance above the sea surface. Up to four separate offshore HVDC converter substations will be required. The Maximum design scenario for this can be seen in Table 3.32 below.

3.6.8.14 Hornsea Three requires flexibility in location and foundation choice of the offshore HVDC convertor substations (see section 3.6.4) to ensure that anticipated changes in available technology and project economics can be accommodated within the Hornsea Three design.

Table 3.32: Maximum design scenario for offshore HVAC converter substations.

Parameter	Maximum design scenario
Number of offshore HVDC converter substations	4
Length of topside (m)	180
Width of topside (m)	90
Topside area (m²)	16,200
Topside - height (excluding helideck or lightning protection) (LAT)	100
Height of lightning protection above topside (LAT)	110
Diesel fuel (l)	200,000

3.6.8.15 It is possible that the design approach for offshore HVDC converter substations will move towards multiple smaller units, rather than fewer large units. In this case, the Maximum design scenario for the smaller offshore transformer substations (as in Table 3.30) would apply, however the total number of offshore transformer substations would be up to 12 and up to four offshore HVDC converter substations, not exceeding 16 in total.

Installation

3.6.8.16 Dependent on the design of the offshore HVDC converter substations, installation may be as for the offshore transformer substations (as described in paragraph 3.6.8.1), alternatively a 'float-over' installation may be used. This type of installation, usually used with gravity base structures, is similar to that described in paragraph 3.6.4.54, however it may also be advantageous to pre-assemble the topside and foundation in the fabrication yard or staging port, and float the whole substation structure to site in a single trip. The vessel requirements for installation can be seen in Table 3.31.

Offshore HVAC booster station(s)

3.6.8.17 Offshore HVAC booster station(s) are required in HVAC transmission systems only; they are not required in HVDC transmission systems.

3.6.8.18 Long distance, large capacity HVAC transmission systems require reactive compensation equipment to reduce the reactive power generated by the capacitance of the export cable in order to allow the power delivered to the National Grid to be useable. The electrical equipment required to provide the reactive compensation, in the form of an HVAC booster station, can be located onshore, on an offshore platform, or within a subsea structure. Alternatively a combination of these options could be used.

3.6.8.19 Hornsea Three requires flexibility in location, type and foundation choice for offshore HVAC booster station(s) (see section 3.6.4) to ensure that anticipated changes in available technology and project economics can be accommodated within the Hornsea Three design.

Location

3.6.8.20 If required, this infrastructure would be located in the Hornsea Three offshore cable corridor, rather than in the array area.

3.6.8.21 An area starting at approximately 40% of the total cable route length (offshore and onshore) and continuing to approximately 60% of the total cable route length, has been identified as the offshore HVAC booster station location search area (see Figure 3.1). This area has been chosen based on preliminary electrical design studies indicating this location may be electrically optimal. The final location of the offshore HVAC booster stations will be defined in the detailed design stage, post consent. The siting will take into account stakeholder input provided in response to this PEIR, as well as final electrical design, water depth, ground conditions and other engineering and economic factors to ensure a location is chosen to minimise impact to the human and natural environment as well as minimising cost of electricity and project risk.

3.6.8.22 There may also be a requirement for an onshore HVAC booster station either instead of or as well as the offshore HVAC booster station(s). This is described in section 3.7.2.

Surface

Design

3.6.8.23 Although the different substations perform different functions, and contain differing internal electrical equipment, the external design of a surface offshore HVAC booster station will be very similar to the offshore transformer substations described in paragraphs 3.6.8.1 to 3.6.8.9. The Maximum design scenario is set out in Table 3.33.

Installation

3.6.8.24 Installation will be as for the offshore transformer substations (as described in 3.6.8.1). The vessel requirements for installation can be seen in Table 3.31.

Table 3.33: Maximum design scenario for surface offshore HVAC booster station(s).

Parameter	Maximum design scenario
Number of surface offshore HVAC booster stations	4
Topside – main structure length and width (m)	90
Topside – ancillary structure length and width (m)	100
Topside - height (excluding helideck or lightning protection) (LAT) (m)	70
Height of lightning protection above topside (LAT) (m)	90
Transformer/reactor oil (kg)	225,000
Diesel Fuel (l)	20,000
Sulphur hexafluoride (SF6) (kg)	1,500
Batteries (lead acid gel) (kg)	6,000

Subsea

Design

3.6.8.25 Although this technology is known to be being developed by the supply chain, at the time of writing no subsea offshore HVAC booster station(s) have been constructed for HV power transfer, therefore the details of this type of structure are primarily based on knowledge of surface designs as well as an understanding of subsea structures used in the offshore oil and gas industry. The structure would likely be a sealed steel or concrete structure, similar to the topside of an offshore substation but fixed to the seabed with piles, and without any substructure required to lift it above the sea surface. It is not expected that this structure would be regularly accessed for operation and maintenance during Hornsea Three's lifetime. The Maximum design scenario can be seen in Table 3.34, and illustration of this type of structure can be seen in Figure 3.16.

Lighting and marking

3.6.8.26 The lighting and marking of the structure (as well as all other Hornsea Three structures) will be discussed and specified in consultation with Trinity House Lighthouse Services (THLS), having a statutory duty as a General Lighthouse Authority. This will be necessary to mitigate any risk to shipping that will be presented by a subsea offshore HVAC booster station(s). The marking will be based on the recommendations of the International Association of Marine Aids to Navigation and Lighthouse Authorities (IALA, 2013). The positions of the structure and export cable will be conveyed to the UK Hydrographic Office so that they can be incorporated into Admiralty Charts and the Notice to Mariners procedures.

Installation

3.6.8.27 The exact installation procedure for subsea offshore HVAC booster station(s) is currently unknown, however it is likely that the structure will be preassembled at the fabrication yard and brought to site by either on a barge or on the installation vessel. The installation vessel will then lower the structure to the seabed and secure the structure to the seabed with piles either installed in advance or afterwards.

3.6.8.28 Installation will be as for the offshore transformer substations (as described in paragraph 3.6.8.26). The vessel requirements for installation can be seen in Table 3.31.

Table 3.34: Maximum design scenario for subsea offshore HVAC booster station(s).

Parameter	Maximum design scenario
Number of subsea offshore HVAC booster stations	6
Subsea structure: length (m)	50
Subsea structure: width (m)	50
Subsea structure: height above seabed (m)	15
Subsea structure: number of piles per substation	12
Piles: penetration depth (m)	50
Piles: diameter (m)	2

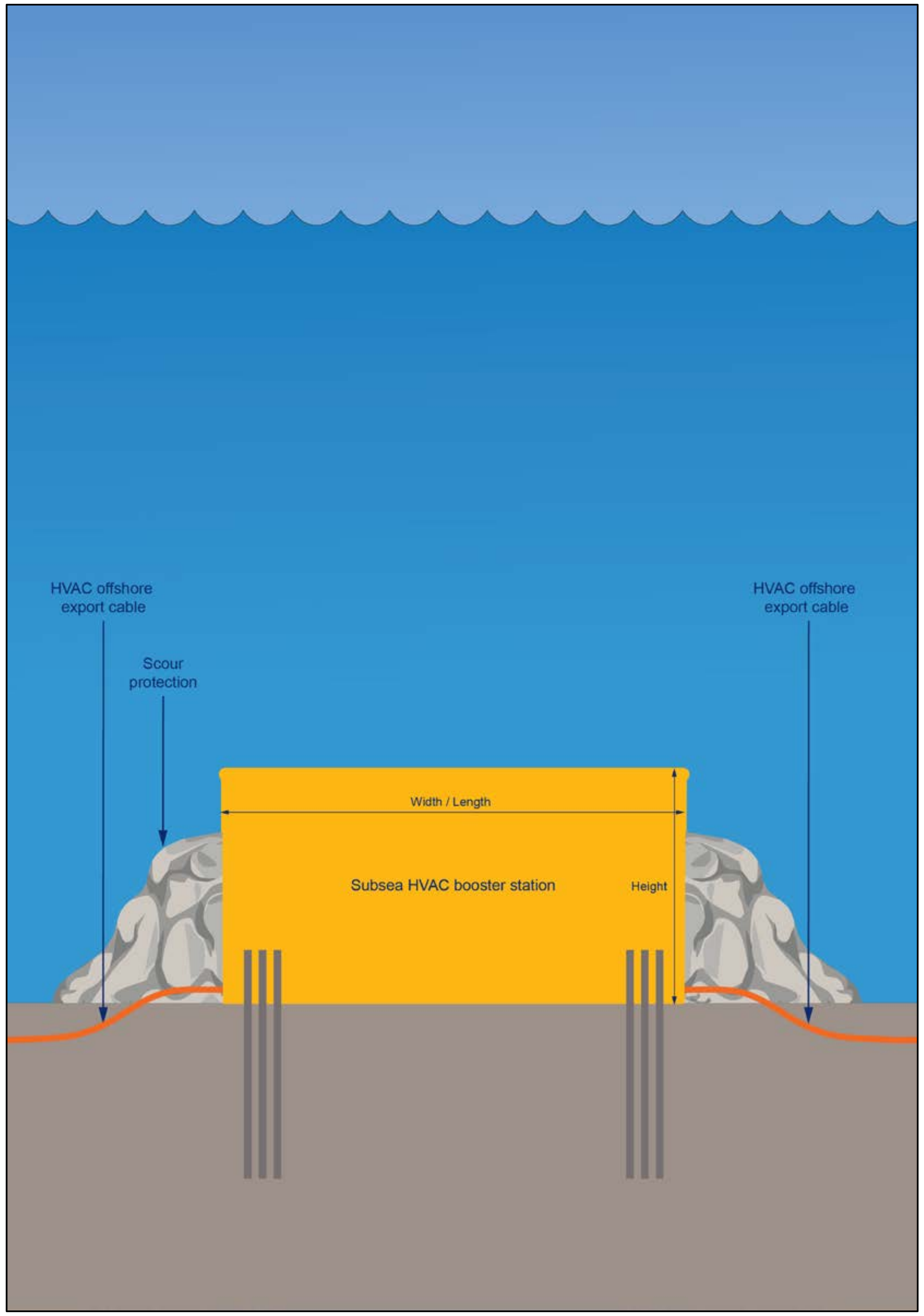


Figure 3.16: Illustration of subsea offshore HVAC booster station.

3.6.9 Offshore export cables

3.6.9.1 Offshore export cables are used for the transfer of power from the offshore substations to the landfall point. For HVAC transmission systems offshore export cables will carry electricity from the offshore transformer substations to the offshore HVAC booster station(s) and then on to the landfall. For HVDC transmission systems, offshore export cables will carry electricity from the offshore transformer substations to the offshore HVDC converter substations and then to the landfall. Up to six offshore export cables, with a voltage of up to 600 kV will be required for Hornsea Three. If possible the cables will be buried below the seabed through to landfall.

3.6.9.2 Hornsea Three requires flexibility in type, location, depth of burial and protection measures for export cable to ensure that anticipated physical and technical constraints and changes in available technology and project economics can be accommodated within the Hornsea Three design.

Design

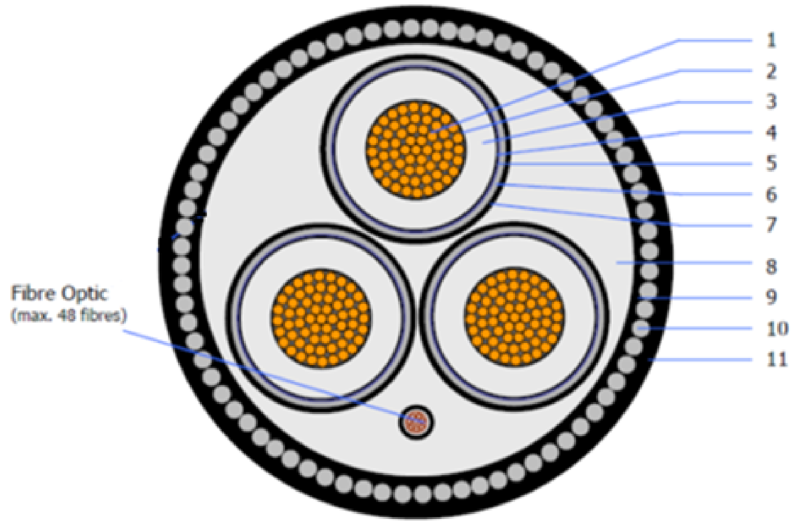
3.6.9.3 Like the array cables (see section 3.6.5), the export cables will consist of a number of conductor cores, usually made from copper or aluminium. These will be surrounded by layers of insulating material as well as material to armour the cable for protection from extremal damage and material to keep the cable watertight. Export cables are however typically larger in diameter than array cables, due to the larger conductor cores required to transport greater volumes of power.

3.6.9.4 The Maximum design scenario for array cables is shown in Table 3.35. An example of an offshore export cable (HVAC 220 kV) is shown in Figure 3.17.

Table 3.35: Maximum design scenario: offshore export cables.

Parameter	Maximum design scenario
HVAC - number of circuits	6
HVAC – voltage (kV)	400
HVDC - number of circuits	4 (plus one HVAC circuit) [a]
HVDC – voltage (kV)	600
Cable diameter (mm)	320

a Assuming a maximum of four HVDC circuits plus one HVAC circuit which may be required to supply power from the onshore HVDC converter/HVAC substation to the offshore wind farm in some HVDC system designs.



(Diagrammatic only – not to scale)

1. Plain Cu conductor	2. Conductor screen
3. XLPE Insulation	4. Insulation screen
5. Longitudinal water barrier	6. Lead sheath
7. PE semi conductive sheath	8. Fillers
9. Binder tape and string bedding	10. Galvanised wire armour
11. String serving in double layer	

Figure 3.17: Cross section through a typical offshore alternating current (AC) (220 kV) export cable (Courtesy of Prysmian).

Offshore cable corridor

3.6.9.5 The offshore cable route corridor can be seen in Figure 3.1 , and the maximum design scenario for the offshore cable route can be seen in Table 3.36.

Table 3.36: Maximum design scenario: offshore export cable route.

Parameter	Maximum design scenario
Length of export cable corridor (km)	145
Export cable corridor width (km)	1.5
Length of export cable route – Including export cable within the array area (km)	173
Total length of export cables (km)	1,038

Installation

3.6.9.6 The export cable installation methodology as well as the burial depth and any requirement for protection measures will be defined by a detailed Cable Burial Risk Assessment (CBRA). Typically the cable will be buried between 1 - 2m. The CBRA will inform cable burial depth which will dependent on ground conditions as well as external risks. This assessment will be undertaken post-consent.

3.6.9.7 It is likely the installation techniques will consist of one or a combination of trenching, dredging, jetting, ploughing, vertical injection, MFE and rock cutting.

3.6.9.8 As with the array cables, the export cables will need to be made secure where the route crosses obstacles such as exposed bedrock, pre-existing cables or pipelines that mean the cable cannot be buried. This is typically achieved through some form of armouring (rock, mattress or proprietary separation layer) to maintain the integrity of the cable. Up to 10% of the total export cable length may require protection due to ground conditions(this excludes cable protection due to cable crossings). The methodology and parameters would be as described in section 3.6.4.44 for array cables. Up to 37 crossings per export cable may need to be undertaken with associated cable protection as described in paragraph 3.6.4.44.

3.6.9.9 The maximum design scenario for offshore export cable installation can be seen in Table 3.37. the basis of the volume calculations is as described in Table 3.23.

Table 3.37: Maximum design scenario: offshore export cables installation.

Parameter	Maximum design scenario
Installation methodology	Trenching, dredging, jetting, ploughing, mass flow excavation, vertical injection, rock cutting
Seabed disturbance (m^2)	14,460,000
Rock protection area (m^2)	726,600
Rock protection volume (m^3)	1,038,000
Burial spoil: jetting (m^3)	2,293,980
Burial spoil: ploughing/mass flow excavation (m^3)	6,228,000
Sand wave clearance volume in export cable route corridor (m^3)	182,056 m^3
Sand wave clearance volume in array area (for export cable) (m^3)	22,750
Duration (months)	36

3.6.9.10 Cable installation and route preparation will be undertaken by specialist vessels, the vessel requirements for offshore export cable installation can be found in Table 3.38.

Table 3.38: Maximum design scenario: offshore export cables vessel and helicopter requirements.

Parameter	Maximum design scenario
Main laying vessels	3
Main jointing vessels	3
Main burial vessels	3
Support vessels: crew boats/service vessels	4
Support vessels: service vessel for pre-rigging	2
Support vessels: diver vessels	2
Support vessels: vessels for PLGR	2
Support vessels: dredging vessels	3
Support vessels: survey vessels	2
Main laying vessels (return trips)	180
Main jointing vessels (return trips)	120
Main burial vessels (return trips)	180
Support vessels (return trips)	270
Helicopter support (return trips)	1684

Crossings

3.6.9.11 The Hornsea Three offshore cable corridor crosses a number of existing assets, primarily oil and gas pipelines that connect to production wells in the North Sea. The design and methodology of these crossings will be confirmed in agreements with the asset owners, however it is likely that a berm of rock will be placed over the existing asset for protection, known as a pre-lay berm, or separation layer. The export cable will then be laid across this, at an angle close to 90 degrees. The export cable will then be covered by a second post lay berm to ensure that the export cable remains protected and in place. The rock berms will be inspected at regular intervals and may need to be replenished with further rock placement dependent on their condition. This operational rock placement would not exceed 25% of the original rock volume. The parameters for these crossings can be found in Table 3.39 below.

Table 3.39: Maximum design scenario: offshore export cables crossings.

Parameter	Maximum design scenario
Number of external assets requiring crossings	37
Replenishment during operations (% of construction total)	25
Cable/pipe crossings: pre-lay rock berm: seabed area – per crossing (m^2)	600
Cable/pipe crossings: pre-lay rock berm: rock volume at construction – per crossing (m^3)	500
Cable/pipe crossings: pre-lay rock berm: rock volume including operation – per crossing (m^3)	625
Cable/pipe crossings: post-lay rock berm: seabed area – per crossing (m^2)	2,800
Cable/pipe crossings: post-lay rock berm: rock volume at construction – per crossing (m^3)	1,600
Cable/pipe crossings: post-lay rock berm: rock volume including operation– per crossing (m^3)	2,000
Cable/pipe crossings: total seabed area – per crossing (m^3)	3,316
Cable/pipe crossings: total seabed rock volume including operation – per crossing (m^3)	2,625
Rock protection area and volume: area (m^2)	726,600
Rock protection area and volume: volume (m^3)	1,038,000
Cable/pipe crossings: pre-lay rock berm area and volume: area (m^2)	22,200
Cable/pipe crossings: pre-lay rock berm area & volume: volume (m^3)	23,125
Cable/pipe crossings: post-lay rock berm area and volume: area (m^2)	103,600
Cable/pipe crossings: post-lay rock berm area and volume: volume (m^3)	74,000

Sandwave clearance

3.6.9.12 The final cable routing will, where feasible, aim to avoid existing sand waves along the offshore cable corridor, however there may be the need to clear sand waves, particularly in areas with extensive sandwaves, in order to provide a flat surface stable enough to allow the installation tools to install the cable to the required depth. See section 3.6.5.9 for further details and Table 3.40 for the maximum design scenario for sandwave clearance for the export cable route.

Table 3.40: Export cable route sandwave clearance.

Parameter	Maximum design scenario
Length of route affected by sandwaves (km)	34
Sand-wave clearance: Contingency (%)	50
Sand-wave clearance: Export Cable Route Total (m^3)	182,056
Sand-wave clearance: Export Cable Within Array Area Total (m^3)	22,750
Sand-wave clearance: Cromer Chalk bed MCZ (KPs 18 – 21) (m^3)	0
Sand-wave clearance: North Norfolk Sandbanks and Saturn Reef (KPs 58 – 127) (m^3)	121,200
Sand-wave clearance: Total in array area (export cables, array cables, interconnector cables) (m^3)	168,325
Sand-wave clearance: Total in Markhams Triangle (export cables, array cables, interconnector cables) (m^3)	33,595

3.6.10 Offshore interconnector cables

3.6.10.1 Hornsea Three may require power cables to interconnect the offshore substations in order to provide redundancy in the case of cable failure elsewhere, or to connect to the offshore accommodation platforms in order to provide power for operation. The cables will have a similar design and installation process to the offshore export cables and array cables. The parameters for design and installation of the offshore interconnector cables can be found Table 3.41 and Table 3.42.

Table 3.41: Maximum design scenario: offshore interconnector cables.

Parameter	Maximum design scenario
Number of cables	15
Total cable length (km)	225
Voltage (kV)	600

Table 3.42 Maximum design scenario: offshore interconnector cables installation.

Parameter	Maximum design scenario
Installation methodology	Trenching, dredging, jetting, ploughing, mass flow excavation, vertical injection, rock cutting
Burial Depth	Typically 1-2m. Dependent on CBRA [a]
Seabed disturbance (excluding sandwave clearance) (m^2)	2,250,000
Burial spoil: jetting (m^3)	497,250
Burial spoil: ploughing/mass flow excavation (m^3)	1,350,000
Rock protection area (m^2)	157,500
Rock protection volume (m^3)	225,000
Number of crossings (total)	2
Cable/pipe crossings: pre-lay rock berm area (m^2)	1,200
Cable/pipe crossings: pre-lay rock berm volume (m^3)	1,250
Cable/pipe crossings: post-lay rock berm area (m^2)	5,600
Cable/pipe crossings: post-lay rock berm volume (m^3)	4,000
Sand wave clearance volume (m^3)	30,469
Total seabed disturbance (m^2)	2,293,20

a Typically the cable will be buried between 1 – 2 m. A Cable Burial Risk Assessment (CBRA) will inform cable burial depth, dependent on ground conditions as well as external risks. This assessment will be undertaken post-consent.

3.6.11 Landfall

3.6.11.1 The offshore export cables will make landfall near Weybourne Hope in North Norfolk. Figure 3.18 shows the offshore cable corridor at the landfall, and the onward terrestrial cable corridor that is proposed east and west of the town of Weybourne.

3.6.11.2 The works at the landfall comprises the works required to bring the offshore export cables through the intertidal area to a location where they can be connected to the onshore export cables. The offshore cables are connected to the onshore cables at the Transition Joint Bays (TJBs).) The works at the landfall would primarily be the same irrespective of whether HVAC or HVDC transmission is selected.

3.6.11.3 TJBs are pits dug and lined with concrete, in which the jointing of the offshore and onshore export cables takes place. One TJB is required per export cable circuit. They are constructed to ensure that the jointing can take place in a clean, dry environment, and to protect the joints once completed. Once the joint is completed the TJBs are covered and the land above reinstated. It is not expected that the TJBs will need to be accessed during the operation of the wind farm, however link boxes (see paragraph 3.6.4.10) need to be located nearby that do require access during the operational phase, these will also be reinstated but may have manhole covers for access. Additional TJBs may be required at the landfall, to allow for flexibility during the construction process. To account for this scenario the envelope includes for eight TJBs at the landfall.

3.6.11.4 During landfall works, a construction compound is required on the onshore side of the beach. This will house the TJB works as well as any Horizontal Directional Drilling (HDD) works, including supporting equipment and facilities. The maximum design scenario for the TJBs and landfall can be seen in Table 3.43 below.

3.6.11.5 The techniques used to carry out the landfall works broadly fall in to two categories; open cut installation or trenchless techniques (i.e.HDD or thrust boring) It may be possible to carry out a HDD to beyond the intertidal area, and install the rest of the cable using an offshore installation spread. The technical feasibility of this approach will require confirmation via an intrusive geotechnical survey campaign. However, it may also be the case that the HDD is not possible (due to ground conditions, cable design, or other factors), in which case open cut techniques would be required to install the cable from offshore to the TJBs. It may also be the case that a HDD could be carried out to cross the shingle beach but would not reach the offshore area. In which case both methods would be required to carry out the landfall works.

3.6.11.6 Hornsea Three is currently conducting a number of geotechnical and geophysical surveys at the landfall site to confirm the technical feasibility of these approaches. The results of these surveys will be used to develop the methodology of the landfall works which will be presented within the Environmental Statement.

3.6.11.7 The requirements for access to the beach and foreshore from the land are currently being developed and further detail will be provided in the Environmental Statement.

Table 3.43: Maximum design scenario for TJBs and landfall works.

Parameter	Maximum design scenario
Number of TJBs	8
TJB area (m^2)	250
TJB depth (m)	6
Landfall compound (m^2)	6,000
TJB working area (per TJB) (m^2)	1,600
Duration of trenching works (per cable) if open cut (weeks)	2
Duration of works for each HDD (months)	3
Duration of works (start – finish) (months)	24
Typical daily (non-HGV) vehicle movements	10
Typical daily HGV movements	5
Total (non-HGV) vehicle movements	1,200
Total HGV movements	600

Figure 3.18: Export cable route corridor at landfall.

Trenchless techniques

Horizontal Directional Drilling (HDD)

3.6.11.8 HDD involves drilling a long parabolic borehole underneath the surface of the sea defences and the intertidal area using a drilling rig located in the TJB works area on the landward side of the sea defences. The process uses a drilling head controlled from the rig to drill a pilot hole along a predetermined profile based on an analysis of the 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. Bentonite is pumped to the drilling head during the drilling process to stabilise the hole and ensure that it does not collapse. Prior to the drilling taking place, an exit pit may be excavated in the intertidal or nearshore area of the export cable route in order for the HDD profile and ducts to stop at the required installation depth for the cable. An example of a HDD rig undertaking a HDD for an export cable landfall can be seen in Figure 3.19.

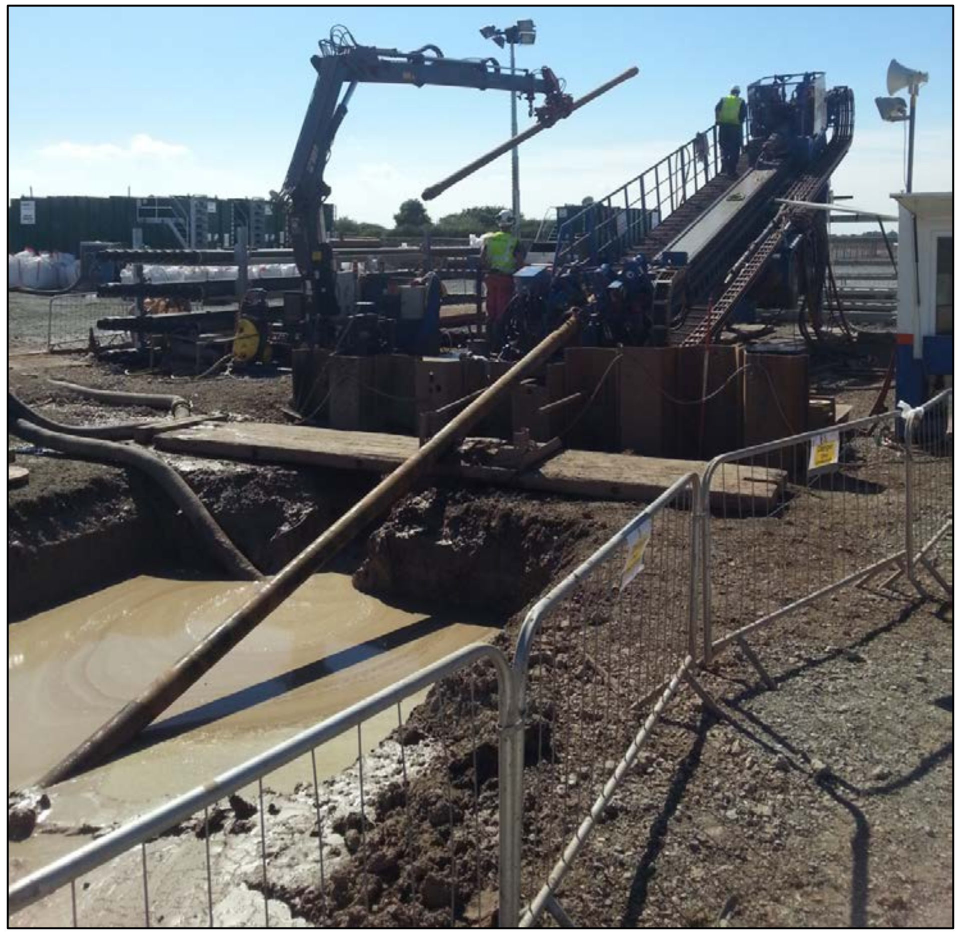


Figure 3.19: HDD rig carrying out landfall works at the Westermost Rough Offshore Wind farm.

3.6.11.9 Once the HDD drilling has taken place the ducts (within which the cable will be installed) are pulled through the drilled hole. These ducts are either constructed offsite, then sealed and floated to the site by tugs, or are constructed behind the beach, usually using the area for the onshore export cable, then pulled over the beach on rollers. The ducts are then pulled back through the drilled hole either by the HDD rig or by separate winches. When the offshore export cable is installed it is pulled through the pre-installed HDD ducts by winches in the TJB working area. The maximum design scenario for HDD at the landfall can be found in Table 3.44 below.

Table 3.44: Maximum design scenario for landfall HDD.

Parameter	Maximum design scenario
HDD cable ducts	8
Diameter of ducts (m)	0.75
HDD working area (m^2) (within landfall working compound)	6,000
Length of ducts (km)	2.5
HDD burial depth maximum (m)	40
HDD burial depth minimum (m)	5
HDD exit pits number	8
HDD exit pits length (m)	50
HDD exit pits width (m)	30
HDD exit pits depth (m)	4

Thrust boring

3.6.11.10 A thrust bore technique may also be used to cross the beach. This process is similar to the HDD process described above, but can only be performed in a straight profile rather than an arc. For this reason, it is used less frequently than HDD, but may be required dependent on the findings of the initial surveys and design studies.

3.6.11.11 As the drill can only be carried out in a straight line, pits must be dug at both ends of the planned drill to below the level required for the cable so the drilling rig can carry out the drill horizontally, and the ducts can be installed. These pits would be up to 25 m long, 5 m wide and 6 m deep. Two pits would be required per duct, one on the landward side, and another in the intertidal area.

Open cut installation

3.6.11.12 The open cut installation would be carried out using one of a number of methods. Installation tools, such as ploughs, rock cutters or jetting tools, similar to those used offshore, can be pulled from the offshore installation vessel, or from winches within the TJB working area, over a pre-laid cable to simultaneously open a trench, place the cable in the trench, and cover the cable. Alternatively, the trenching tool may open a trench in advance, the cable would be lowered into this trench and covered, after it has been pulled across the beach. These tools are usually pulled along the beach on skids or are tracked. All the installation techniques described for the offshore cable installation are applicable to the landfall installation, excluding dredging. Figure 3.20 shows an example of this type of installation tool.

Figure 3.20: Example of a cable plough pulled from an installation vessel. (Source: http://www.4coffshore.com/s/about/equipmentTypes.aspx)

3.6.11.13 Alternatively, self-powered bespoke installation tools may be used. These are usually tracked vehicles, that excavate a trench, lay the cable, and then bury the cable simultaneously. Alternatively, they may excavate a trench in advance, then post lay the cable after the pull to the TJB. They are similar to the tools described above, but are self-powered vehicles that are either controlled from on board the vehicles themselves, or are (Remotely Operated Vehicle (ROV) type systems, controlled from and connected to the offshore installation vessel. Figure 3.21 shows this type of installation tool.

Figure 3.21: The 'sunfish' installation tool as used for cable installation at the Race Bank offshore wind farm.

3.6.11.14 Traditional mechanical excavators, similar to those that would be used to dig TJBs and exit pits etc., can also be used for cable installation. In this process the cable would be pulled from the offshore installation vessel through the intertidal area on rollers placed on the ground. The cable would then be moved from the rollers into a neighbouring trench usually excavated before the cable is laid across the beach.

3.6.11.15 If it is not possible to cross the beach using HDD or thrust boring, mechanical excavators may be used to install a trench to the TJB locations.

3.6.12 Vessel activities

3.6.12.1 The total vessel numbers, vessel movements, and durations are collated in table Table 3.45 below. Each vessel movement represents a return trip to and from the array site.

Table 3.45: Total values for vessel activities during construction phase.

Wind turbine installation information	Maximum design scenario
Installation vessels	4
Support vessels	24
Transport vessels	12
Installation vessels movements	342
Support vessels movements	2,052
Transport vessels movements	1,026
Helicopters movements	257
Monopiles (WTG) construction (standard assumptions for other foundations if not stated)	
Installation vessels	4
Support vessels	16
Transport vessels (barges and tugs)	10 + 30
Feeder barge concept - installation vessels movements	342
Feeder barge concept - support vessels movements	1,368
Feeder Barge concept - transport barge movements	171
Feeder Barge concept - transport barge tug movements	513
Helicopters movements	684
Gravity Base (WTG) – construction (mutually exclusive with Monopile values above)	
Installation vessels	3
Support vessels	13
Dredging vessels	12
Tug vessels	4
Self-installing concept - support vessels movements	1,710
Self-installing concept - dredging vessels movements	1,368
Self-installing concept - tugs movements	1,368
Substation foundations construction	
Primary installation vessels	2
Support vessels	12
Transport vessels	4
Primary installation vessels movements	38
Support vessels movements	228
Transport vessels movements	38
Helicopter movements	532
Inter-array cables installation	
Main laying Vessels	3
Main burial Vessels	3
Support vessels: crew boats or SOVs	4
Support vessels: service vessel for pre-rigging of towers	2
Support vessels: diver vessels	2
Support vessels: vessels for PLGR	2
Support vessels: dredging vessels	2
Main laying Vessels movements	357
Main burial Vessels movements	357
Support vessels movements	2,142
Helicopter movements	684
Export cables installation	
Main laying vessels	3
Main jointing vessels	3
Main burial vessels	3

Wind turbine installation information	Maximum design scenario
Support vessels: crew boats/service vessels	4
Support vessels: service vessel for pre-rigging of towers	2
Support vessels: diver vessels	2
Support vessels: vessels for PLGR	2
Support vessels: dredging vessels	3
Support vessels: survey vessels	2
Main laying vessels movements	180
Main jointing vessels movements	120
Main burial vessels movements	180
Support vessels movements	270
Helicopters movements	1,684

3.6.13 Safety Zones

3.6.13.1 During construction, and decommissioning Hornsea Three may apply for a 500 m safety zone around infrastructure that is under construction. Safety zones of 50 m may be sought for incomplete structures at which construction activity may be temporarily paused (and therefore the 500 m safety zone has lapsed) such as installed monopiles without transition pieces or where construction works are completed but the wind farm has not yet been commissioned.

3.6.13.2 During operation Hornsea Three may apply for a 500 m safety zone around manned infrastructure (such as Offshore Accommodation Platforms) in order to ensure the safety of the individuals aboard. Hornsea Three may also apply for 500m safety zones for infrastructure undergoing major maintenance (for example a blade replacement).

3.7 Onshore infrastructure

3.7.1 Onshore export cables

3.7.1.1 Onshore export cables will connect to the offshore export cables at the landfall point (see section 3.6.11) and transfer the power onwards to the onshore HVDC converter/HVAC substation (potentially via an onshore HVAC booster station in the case of HVAC, see section 3.7.2. The onshore export cables will be buried for the entirety of the onshore export cable route (ECR). Overhead lines are not proposed for this project.

Onshore export cable route

3.7.1.2 The onshore cable corridor search area used for this PEIR consists of an approximately 200 m wide corridor designed in accordance with a wide range of human, biological and physical constraints as well as technical and commercial considerations. The refined onshore ECR (80 m width) is intended to be located within the onshore cable corridor search area and will be defined prior to the submission of the Environmental Statement with the final DCO application. The onshore cable corridor search area is intended to give sufficient flexibility to accommodate any changes that may be required as new data arises and considering feedback from consultees including individual landowners. An overview of the current onshore cable corridor search area can be seen in Figure 3.22.

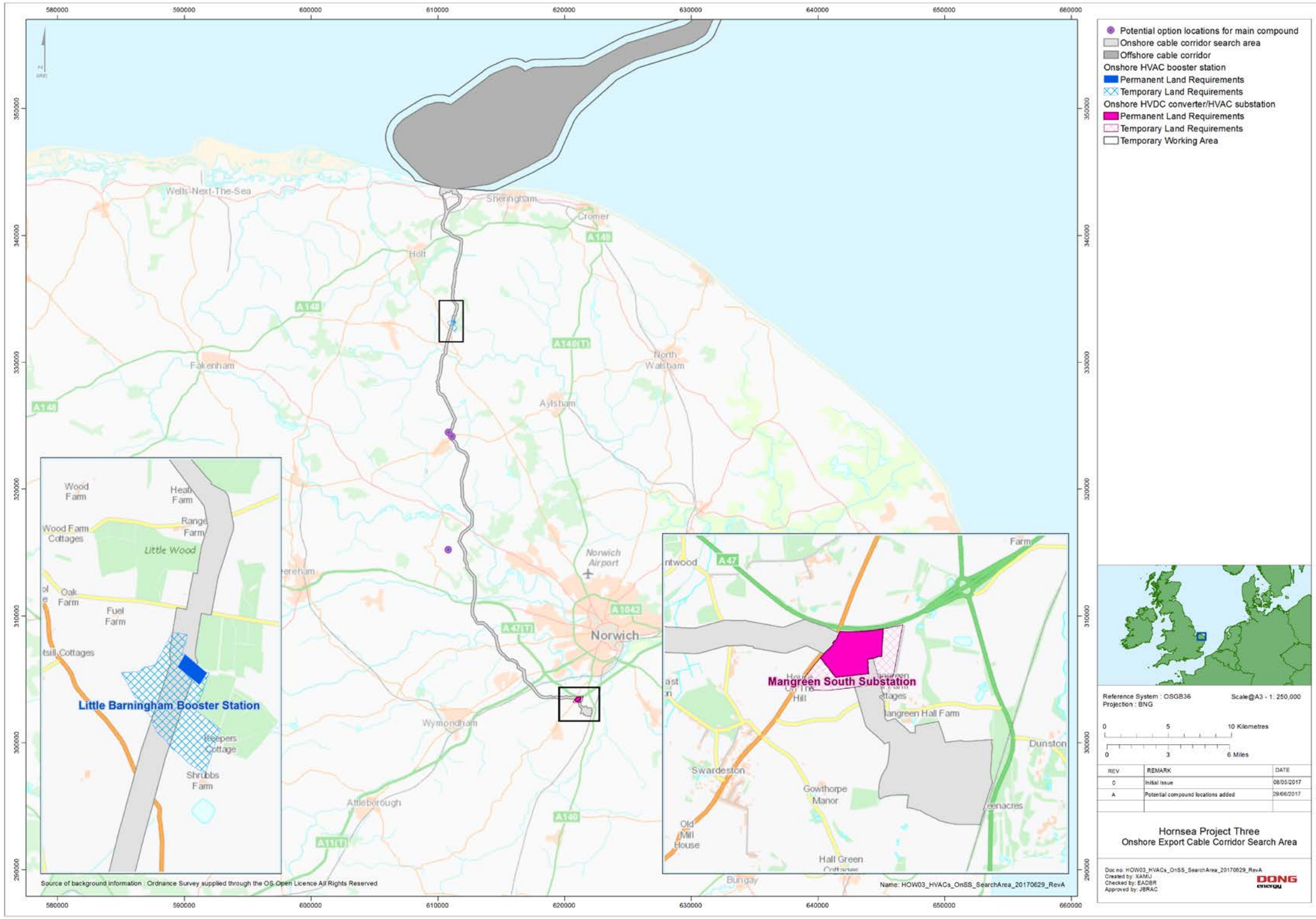


Figure 3.22: Onshore export cable route and locations for HVAC booster station and onshore HVDC converter/HVAC substation.

Design

3.7.1.3 Up to six export cable circuits will be required containing a single conductor with each circuit consisting of three single cables. The cables themselves consist of copper or aluminium conductors wrapped with various materials for insulation, protection, and sealing. Table 3.46 below shows the maximum design scenario for the onshore export cables. Small fibre optic cables may also be buried alongside the export cables in order to allow for communication to the wind farm for the various control systems in place for the project.

3.7.1.4 The potential generation of electro-magnetic field (EMF) effects are a factor of cable burial depth and cable current. The potential for EMF generation from the onshore export cables is considered in volume 4, annex 3.3: EMF Compliance Statement.

Table 3.46: Maximum design scenario: onshore export cables.

Parameter	Maximum design scenario
HVAC - number of cable circuits	6
HVAC - number of cables	18
HVDC – number of circuits [a]	4 (plus one HVAC circuit)
HVDC – number of cables [a]	11
Approximate onshore cable route length (km)	55
Voltage (kV)	600
Diameter of cable (mm) (HVDC)	220
Diameter of duct (mm) (HVDC)	330

a Assuming a maximum of four HVDC circuits plus one HVAC circuit which may be required to supply power from the onshore HVDC converter/HVAC substation to the offshore wind farm in some HVDC system designs.

Installation

3.7.1.5 The cables will be installed within an onshore cable corridor, with an expected width of 80 m (this includes both the permanent installation area and temporary working area). An indicative layout for the route corridor can be seen in Figure 3.25. The width of the permanent and/or temporary areas may change where obstacles are encountered.

3.7.1.6 The cables will be buried in multiple separate trenches (up to six trenches, each containing one circuit), however in some circumstances some trenches may be combined to aid installation. The total combined numbers and volumes will not exceed those stated in Table 3.47. The export cables will be installed in sections of between 750 and 2,500 m at a time, with each section of cable delivered on a cable drum from which it is spooled out as it is installed. The installation of the onshore export cable is expected to take up to 30 months in total, however work is expected to progress along the route with a typical works duration of three months at any particular location. Construction may be carried out by multiple teams at more than one location along the cable route at the same time.

3.7.1.7 During construction of the cable trenches the topsoil and subsoil will be stripped and stored on site within the temporary working corridor of the onshore ECR as construction of each linear section of the route advances. The topsoil and subsoil will be stored in separate stockpiles as shown in Figure 3.25. Once the topsoil is stripped any required temporary roadways will also be installed along the route to allow trench excavation to take place.

3.7.1.8 The trenches will be excavated using a mechanical excavator, and the export cables will be installed into the open trench from a cable drum delivered to site via HGV. The cables are buried in a layer of stabilised backfill material that ensures a consistent structural and thermal environment for the cables. The maximum volumes of imported stabilised backfill material (i.e. that not originating from the excavated trench) are presented in Table 3.47. However, this value is considered to be a maximum and will not be required at most locations along the route. The remainder of the trench is then backfilled with the excavated material. Hard protective tiles, and marker tape are also installed in the cable trenches above the cables to ensure the cable is not damaged by any third party. Once the export cables are installed and the trenches backfilled, the stored topsoil will be replaced and the land reinstated back to its previous use. Each trench section between joint bays (see paragraph 3.7.1.11) is expected to be open for approximately one week.

3.7.1.9 Alternatively, ducts can be installed in the trenches in the same manner as above, and the cables can then be pulled through the ducts from the joint bays. This technique decouples the trenching from the cable installation and therefore can provide more flexibility for the installation process to optimise works and delivery of components.

3.7.1.10 The dimensions of the trenches can be seen in Table 3.47 below. The three cables of a HVAC circuit may either be installed in 'trefoil' formation, whereby two cables sit side by side, with a third sitting above the two cables, or in flat formation where the three cables will all sit side by side at the same level in the trench. The two cables required for HVDC circuits will sit side by side in the trench. The circuits must be spaced out in order to minimise the mutual heating effect of one circuit on another, this enables the cables to effectively carry the large power volumes required without overheating and damaging the cable. The trench and cable corridor layouts can be seen in, Figure 3.24 and Figure 3.25 below.

Table 3.47: Maximum design scenario: onshore export cable installation.

Parameter	Maximum design scenario
Trench width: at base (m)	1.5
Trench width: at surface (m)	5
Corridor width: permanent (m)	60
Corridor width: temporary and permanent (m)	80
Corridor area – permanent (m^2)	3,300,000
Corridor area – temporary and permanent (m^2)	4,400,000
Burial depth: target (m)	1.2
Burial depth: maximum (m)	2
Trench: depth of stabilised backfill (m)	1.5
Cable drums: dimensions (m)	3 × 4
Cable drums: weight (tonnes)	30
Total Installation duration (months)	30

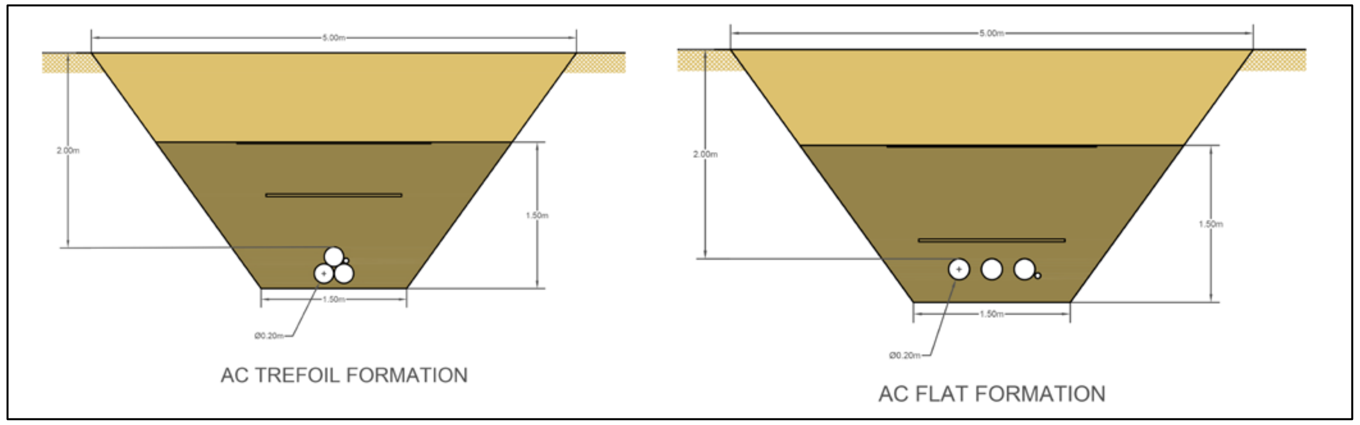


Figure 3.23: Onshore export cable HVAC trench layouts.

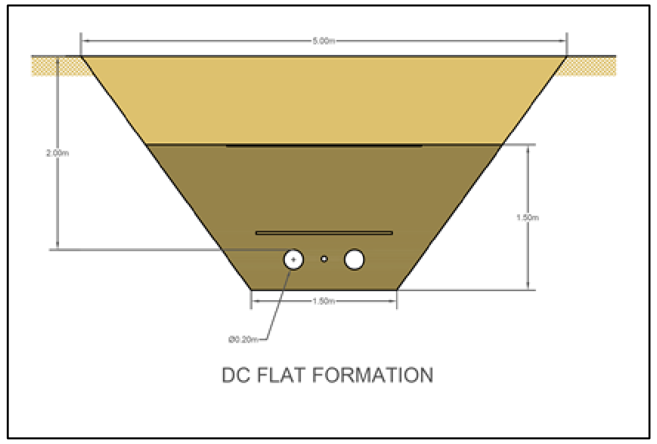


Figure 3.24: Onshore export cable HVDC trench layout.

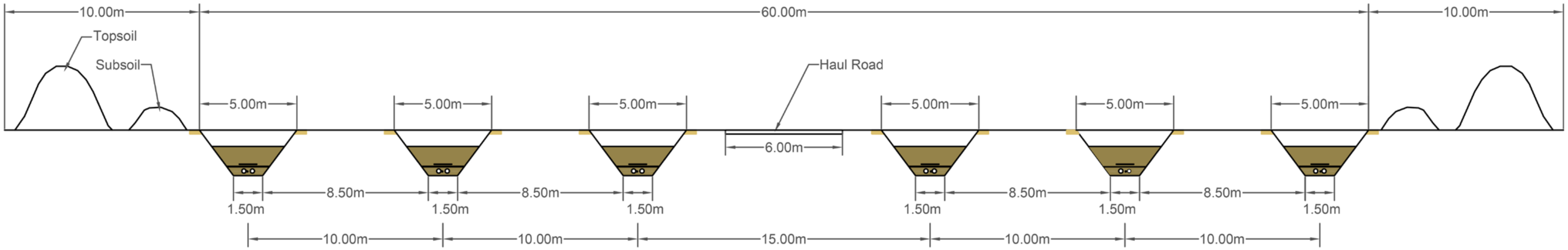


Figure 3.25: Onshore export cable corridor indicative layout.

Joint bays and link boxes

3.7.1.11 Onshore cable joint bays (JBs) will be required along the onshore route, these are typically concrete lined pits, that provide a clean and dry environment for jointing the sections of cable together. These are similar to those described in 3.6.11.3, but are typically smaller. As with the TJBs, these will likely be completely buried, with the land above reinstated. The maximum design scenario for joint bays can be seen in Table 3.48. They will only require access in the event of a cable failure requiring replacement.

Table 3.48: Design envelope: joint bays.

Parameter	Maximum design scenario
Number of JBs	330
Max distance between JBs (on one circuit) (m)	2500
Min distance between JBs (on one circuit) (m) [a]	750
JB width (m)	9
JB length (m)	25
JB area (m^2)	225
JB depth (m)	2.5
JBs - Total area (m^2)	74,250
Spoil volume per JB (m^3)	563
JBs - total spoil volume (m^3)	185,625

a Excluding JBs on either side of trenchless crossings where closer spacing may be required.

3.7.1.12 Link boxes (LBs) will also be required along the onshore route. These are smaller pits compared to joint bays which house connections between the cable shielding, joints for fibre optic cables and other auxiliary equipment. Land above the link boxes will also be reinstated, however, they may need manhole covers for access during the operational phase. The maximum design scenario for link boxes can be seen in Table 3.49.

Crossings

3.7.1.13 The onshore export cables will need to cross infrastructure and obstacles such as roads, railways and rivers. Hornsea Three will aim to undertake all major crossings, such as major roads, rivers and rail crossings using HDD. The detailed methodology for the crossings will be agreed with the relevant stakeholders such as third party asset owners, and other statutory stakeholders. Further detail on the crossing requirements along the route will be developed and presented alongside the Environmental Statement.

Table 3.49: Maximum design scenario: link boxes.

Parameter	Maximum design scenario
Number of LBs	330
Max distance between LBs (on one circuit) (m)	2500
Min distance between LBs (on one circuit) (m) [a]	750
LB dimensions (length & width) (m)	3
LB area (m^2)	9
LB depth (m)	2.0
LBs - Total area (m^2)	2,970
Spoil Volume Per LB (m^3)	18
LBs - Total Spoil Volume (m^3)	5,940

a Excluding LBs on either side of trenchless crossings where closer spacing may be required.

<u>HDD</u>

3.7.1.14 The methodology for HDD crossings will be similar to that described in section 3.6.11.8. The exact depth and length of each HDD will be dependent on the nature of the obstruction being crossed as well as the ground conditions present at each site. Each HDD will require a compound at each side of the crossing to house the HDD rig and the various supporting equipment and components required. Further details on the equipment and processes to be used will be provided for the final ES. For the purposes of the PEIR the indicative details of the HDD compounds can be found in Table 3.52.

Open Cut

3.7.1.15 It may be preferable for certain crossings to be carried out as an open cut crossing, rather than a HDD. These crossings could range from smaller drains, gas and power distribution infrastructure and small roads, to high pressure gas pipelines.

3.7.1.16 For some sensitive infrastructure such as high pressure gas pipelines the area around the pipeline must be carefully excavated by hand and the asset supported before installation of the cables below the pipelines can take place. This is preferred by some asset owners as visual confirmation of the integrity of the asset can be maintained throughout the works.

3.7.1.17 For smaller less sensitive infrastructure it can be quicker and less disruptive to make the crossings using open cut than undertaking the more onerous works required for HDD.

Field drainage

3.7.1.18 It may be necessary to install additional field drainage along the onshore export cable route to ensure the existing drainage characteristics of the land are maintained during and after construction. These drains would be installed either by small trenching machines, open cut trenching or similar. Any drainage design would be agreed with landowners prior to construction. The maximum design scenario for the field drainage can be found in Table 3.50.

Table 3.50: Maximum design scenario: onshore cable route field drainage.

Parameter	Maximum design scenario
Pipe diameter (mm)	250
Trench width (mm)	500
Trench depth (mm)	1,200
Stabilised backfill depth (mm)	1,000

Access and haul roads

3.7.1.19 Access routes will be required from the nearby road network at various places along the onshore export cable route in order to access the construction works as well as the various compounds along the route that may be set-up in advance of the cable laying. The route and design of these access roads will be agreed with the relevant landowners in advance of construction, and Hornsea Three will seek to utilise existing roadways and tracks where possible. It is expected that up to two temporary haul roads will also be required that will run along the export cable route, in parallel to the export cables. Where there are obstacles that must be crossed by the haul roads, such as drainage ditches, temporary culverts or bridges may be installed. An indicative layout of the export cable route corridor, showing the haul road can be seen in Figure 3.25. The maximum design scenario for the haul roads can be seen in Table 3.51. It is expected that any sections of access road that are required to be constructed or widened would be a similar design to the temporary haul roads. Further details will be confirmed prior to the submission of the DCO application.

Table 3.51: Maximum design scenario: onshore cable access and haul roads.

Parameter	Maximum design scenario
Temporary haul road	2
Roadway width (m)	6
Roadway width – passing placed (m)	7
Roadway construction	Crushed aggregate on geo-textile,soil stabilisation or temporary trackway.
Aggregate depth (mm)	600
Temporary culvert/bridge crossings length (m)	10
Temporary culvert/bridge crossings width (m)	6

Temporary construction compounds

3.7.1.20 Construction compounds of various sizes will also be required along the onshore ECR corridor, for laydown and storage of materials, plant and staff, as well as space for small temporary offices, welfare facilities, security and parking.

3.7.1.21 Construction compounds will also be required for crossings of other infrastructure to house operations such as drilling works. They will also be required around joint bay and link box construction.

3.7.1.22 A main construction compound will also be required. This would operate as a central base 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. The main construction compound does not need to be located on the route itself but on a suitable site in a central location in close proximity to the export cable route. Hornsea Three has identified three potential locations for a main compound. These options are shown on Figure 3.22.

3.7.1.23 The construction compounds will be removed and sites restored to their original condition when construction has been completed. It may be necessary to retain some compounds during the commissioning stages of Hornsea Three. New temporary roads or access tracks for construction traffic are likely to be required at various points along the route, connecting compounds and construction sites to existing nearby roads. All compounds will be reinstated to their former condition following the construction phase, unless it is considered necessary to retain the use of a compound for a longer period post-construction. The maximum design scenario for construction compounds can be found in Table 3.52. The final dimensions of the compounds will be dependent on the specific sites themselves, and will be defined in advance of the submission of the Environmental Statement

Table 3.52: Maximum design scenario: onshore cable route construction compounds.

Parameter	Maximum design scenario
Onshore route main compound size (m^2)	40,000
HDD compounds dimensions (length and width) (m)	70 [a]
HDD compound construction duration per compound (month)	1
JB Compounds dimensions (length and width) (m)	40[a]
JB compound vehicles total per compound: vehicles	30
JB compound vehicles total per compound: HGV	10
JB compound construction duration per compound (months)	1
Construction compounds dimensions (length and width) (m)	90 [a]
Construction compounds: area (m^2)	33,000
Construction compound use duration per compound (months)	30

a These values should be considered indicative required dimensions for the proposed works for the purposes of this PEIR, the actual dimensions will be dependent on the location and surrounding environment and may be larger than these values to optimise the use of each specific location.

3.7.2 Onshore HVAC booster station

3.7.2.1 The onshore HVAC booster station would have the same purpose as an offshore HVAC booster station(s), as described in section 3.6.8.17 and contain similar equipment. An onshore HVAC booster station is required for the HVAC transmission only; it is not required for HVDC transmission.

Location

3.7.2.2 The site selection methodology for the onshore HVAC booster station is described in Chapter 4: Site Selection and Consideration of Alternatives. The location of the onshore HVAC booster station can be seen in Figure 3.26.

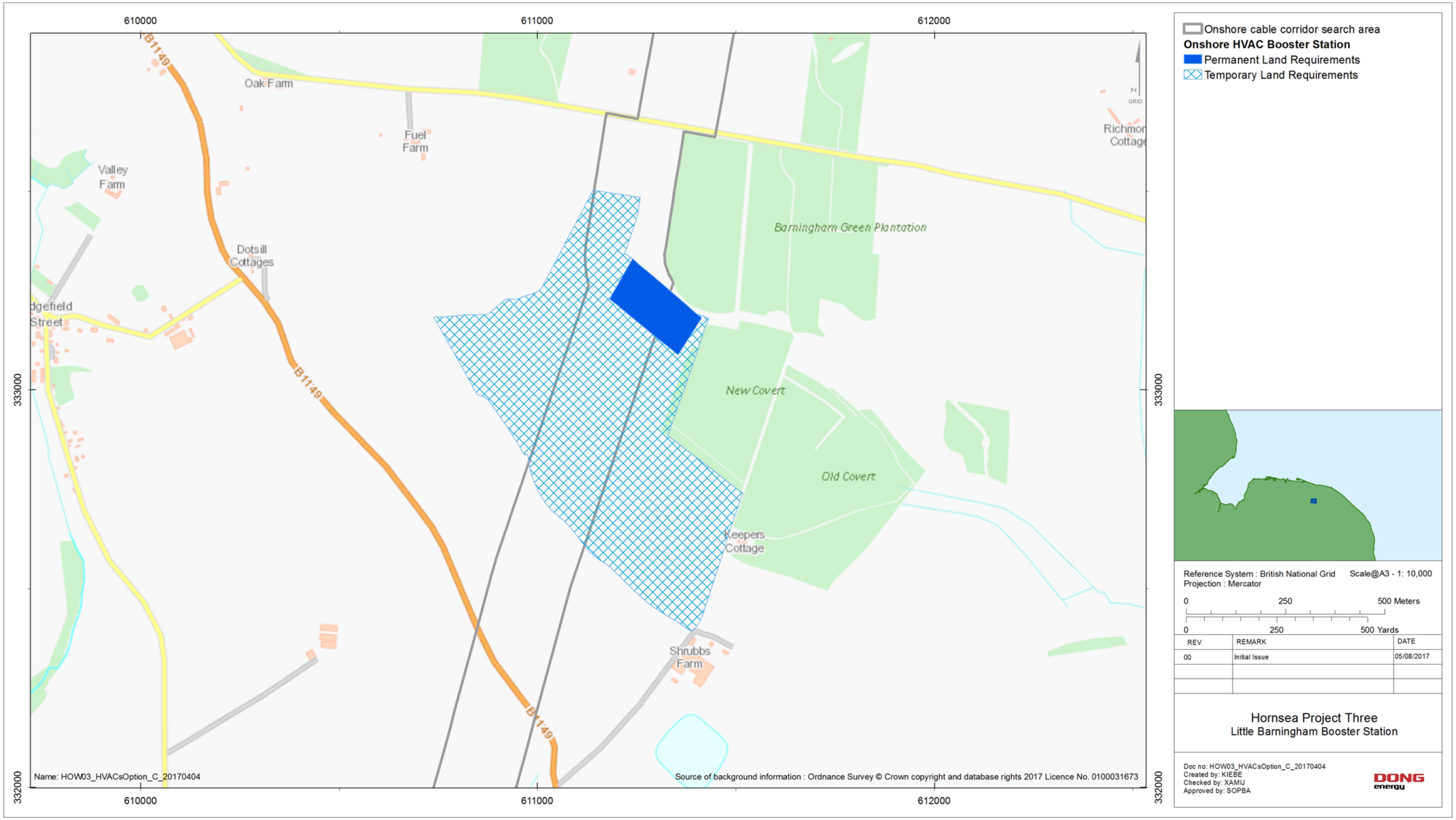


Figure 3.26: Onshore HVAC booster station.

Design

3.7.2.3 The onshore HVAC booster station is primarily composed of High Voltage electrical reactors to correct the power factor of the transmitted electricity, as well as switchgear that connect the reactors into the export cable circuits. The onshore HVAC booster station would also contain auxiliary equipment for running and controlling the onshore HVAC booster station as well as structures to support and house the equipment. The equipment will either be housed within a single or multiple buildings, in an open yard or a combination of the above. There may also be some smaller buildings required to house components such as smaller equipment and control rooms. Indicative layouts for the onshore HVAC booster station are currently being developed and will be delivered included within the Environmental Statement. The Maximum design scenario for the onshore HVAC booster station can be seen in Table 3.53 below.

Table 3.53: Maximum design scenario: onshore HVAC booster station.

Parameter	Maximum design scenario
Permanent area of site for all infrastructure (m^2)	25,000
Temporary area of site for construction works (m^2)	25,000
Single building [a]: length (m)	150
Single building [a]: width (m)	30
Number of buildings	6
Multiple buildings [a]: dimensions (length & width, if 6 buildings) (m)	25
Height of fire walls (m)	12.50
Building: height (m)	12.5
Maximum lightning protection height (m) (from ground level)	17.5

a Note – the onshore HVAC booster station may comprise a single building or multiple buildings on the same site.

Installation

3.7.2.4 The installation of the onshore HVAC booster station will require site preparation and enabling works as described for the onshore HVDC converter/HVAC substation in section 3.7.3. The list of civil engineering works required will be identified as the design of the onshore HVAC booster station develops and will be set out in the Environmental Statement.

3.7.2.5 A temporary working area will be installed adjacent to the onshore HVAC booster station which will be used to contain offices, stores, delivery and offloading areas.

3.7.3 Onshore HVDC converter/HVAC substation options

3.7.3.1 Depending on which transmission option is selected, the “onshore HVDC converter/HVAC substation” will either be an HVAC substation or a HVDC converter substation. For the remainder of this section, when “onshore HVDC converter/HVAC substation” is used, it is taken to mean the onshore HVDC converter substation or the HVAC substation unless otherwise stated.

3.7.3.2 The onshore HVDC converter/HVAC substation contains the electrical components for transforming the power supplied from the offshore wind farm to 400 kV and to adjust the power quality and power factor, as required to meet the UK Grid Code for supply to the National Grid. If a HVDC system is used it will also house equipment to convert the power from HVDC to HVAC.

Location

3.7.3.3 Hornsea Three will connect to the National Grid at the Norwich Main 400 kV substation, located between Swardeston and Stoke Holy Cross in South Norfolk. The Hornsea Three onshore HVDC converter/HVAC substation will also be located in this vicinity. The site selection methodology for the onshore HVDC converter/HVAC substation is described in Chapter 4: Site Selection and Consideration of Alternatives. The proposed for the onshore HVDC converter/HVAC substation can be seen in Figure 3.27 below.

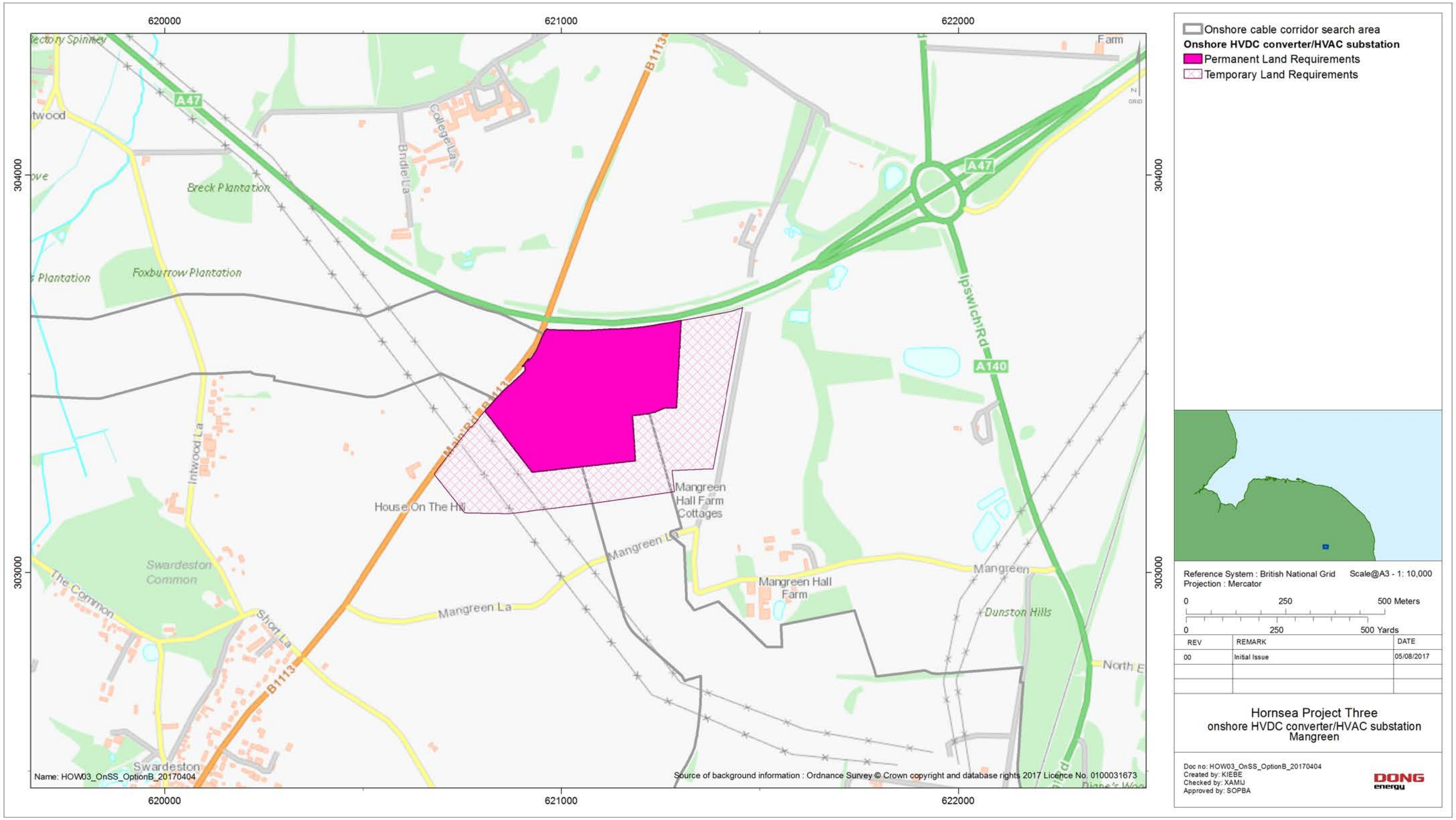


Figure 3.27: Onshore HVDC converter/HVAC substation.

Design

3.7.3.4 The onshore HVDC converter/HVAC substation will consist of a range of equipment for delivery of the power to National Grid such as transformers, reactors, dynamic reactive power compensation plant (As STATCOM) filters and switchgear. It will also include a range of auxiliary and supporting equipment for the running and control of the substation. The main equipment will either be housed within a single or multiple buildings, in an open yard or a combination of the above. If multiple buildings are used the length and width of these buildings would be reduced proportionally to the number of buildings, e.g. if two buildings were used they would each cover half of the area required for the single larger building. There may also be some smaller buildings required to house components such as smaller equipment and control rooms. Indicative layouts for the onshore HVDC converter/HVAC substation are currently being developed and will be delivered within the Environmental Statement. The Maximum design scenario for the onshore HVDC converter/HVAC substation for both HVAC and HVDC options can be seen in Table 3.54 below.

Table 3.54: Maximum design scenario for onshore HVDC converter/HVAC substation.

Parameter	Maximum design scenario
Permanent area of site for all infrastructure (m^2)	128000
Temporary works area (m^2)	100,000
Main building - lightning protection height (m)	30
Height of fire walls (m)	20
HVAC Scenario	
HVAC – maximum number of main buildings	3
HVAC – length of main building (m)	150
HVAC – width of main building (m)	30
HVAC – height of main building (m)	25
HVDC Scenario	
HVDC – maximum number of main buildings	2
HVDC – width of main building (m)	75
HVDC – length of main building (m)	150
HVDC – height of main building(m)	25

Installation

3.7.3.5 The construction works for the onshore HVDC converter/HVAC substation are similar if using either the HVAC or HVDC solutions.

Site preparation, enabling works and civils works.

3.7.3.6 A compound will be set up that includes the permanent area required for the onshore HVDC converter/HVAC substation as well as a temporary working area required for storing and moving equipment and materials during the construction process. The topsoil of the site will be stripped and the site will be levelled as required. Civil works such as the laying of foundations and drainage, as well as the construction of buildings and supporting structures and systems will then be undertaken as required until the site is ready for the delivery of the electrical components.

Electrical component installation and reinstatement

3.7.3.7 The electrical equipment will then be installed and tested in readiness for the connection of the offshore wind farm, and the National Grid substation. Once the construction of the substation is complete the site will be secured and the supporting infrastructure finalised in readiness for the operations phase. The temporary area will be reinstated once construction is complete. The construction works at the onshore HVDC converter/HVAC substation may take up to 36 months. The temporary site may include a temporary viewing platform to enable visitors and staff to safely oversee the construction without entering the construction area itself. onshore HVDC converter/HVAC substation maximum design scenario.

Table 3.55: Maximum design scenario onshore HVDC converter/HVAC substation installation.

Parameter	Maximum design scenario
Temporary area of site for construction works (m^2)	100,000 [a]
Viewing platform height (m)	30
Duration of construction (months)	36

a Additional to that in Table 3.54.

3.7.3.8 Any mitigation required on the site or nearby will be agreed with the relevant stakeholders and installed as appropriate alongside the onshore HVDC converter/HVAC substation works.

3.7.4 Grid connection export cable

3.7.4.1 A further section of buried onshore export cabling is required to connect the Hornsea Three onshore HVDC converter/HVAC substation with the National Grid substation. This section of cabling will be similar in design to the onshore export cabling, but must be HVAC at 400 kV, and will have a maximum of four circuits, with a total of 12 export cables. The parameters of this section of the route are included in that described in section 3.7.

3.8 Construction Phasing

3.8.1.1 A high-level indicative construction programme is presented in Figure 3.28 below where Hornsea Three is constructed in a single phase. The programme illustrates the likely duration of the major installation elements, and how they may relate to one another if built out in a single phase construction campaign. It covers installation of the major components and does not include elements such as preliminary site preparation, and commissioning of the wind farm post-construction. Further details of where preliminary site preparation work will fit within the outline programme will be presented in the final application. Onshore construction is currently planned to commence in 2021.

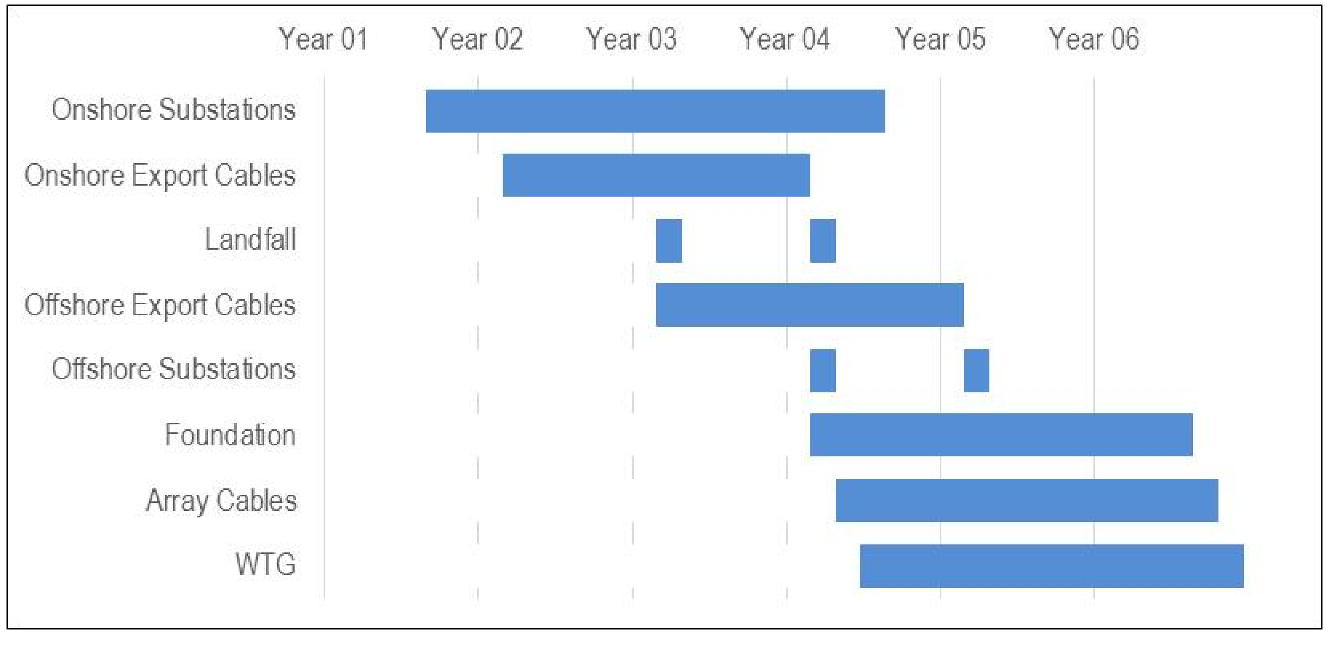


Figure 3.28: Indicative construction programme if project built out in a single phase.

3.8.1.2 Hornsea Three may also be constructed in two or three phases, including the potential for an overlap or a gap between the completion of construction of one phase and the start of construction of another. However, if the construction of any phases are overlapping, the construction durations and total values for individual parameters will never exceed those stated for a single phase. For example, no more than four monopile installation vessels would be in use at any time, and no more than two monopiles would be piled simultaneously, irrespective of any phasing described below.

3.8.1.3 It is possible that some activities may be carried out during an earlier phase for the benefit of a later one. However, any works completed for a later phase(s) would be left in a safe state, as agreed with the relevant authorities, to await the appropriate phase for completion.

3.8.1.4 Figure 3.28 above shows an indicative programme for a single phase construction. Figure 3.29 shows an indicative construction programme where two phases are built out sequentially, whilst Figure 3.30 shows an indicative programme where Hornsea Three is built out in three phases with some of the works being parallel. These figures are provided to demonstrate indicatively how construction elements could be built out in multiple phases but still within total maximum design scenario duration for one phase in either two or three phase construction scenario phases could be sequential, fully or partially overlapping.

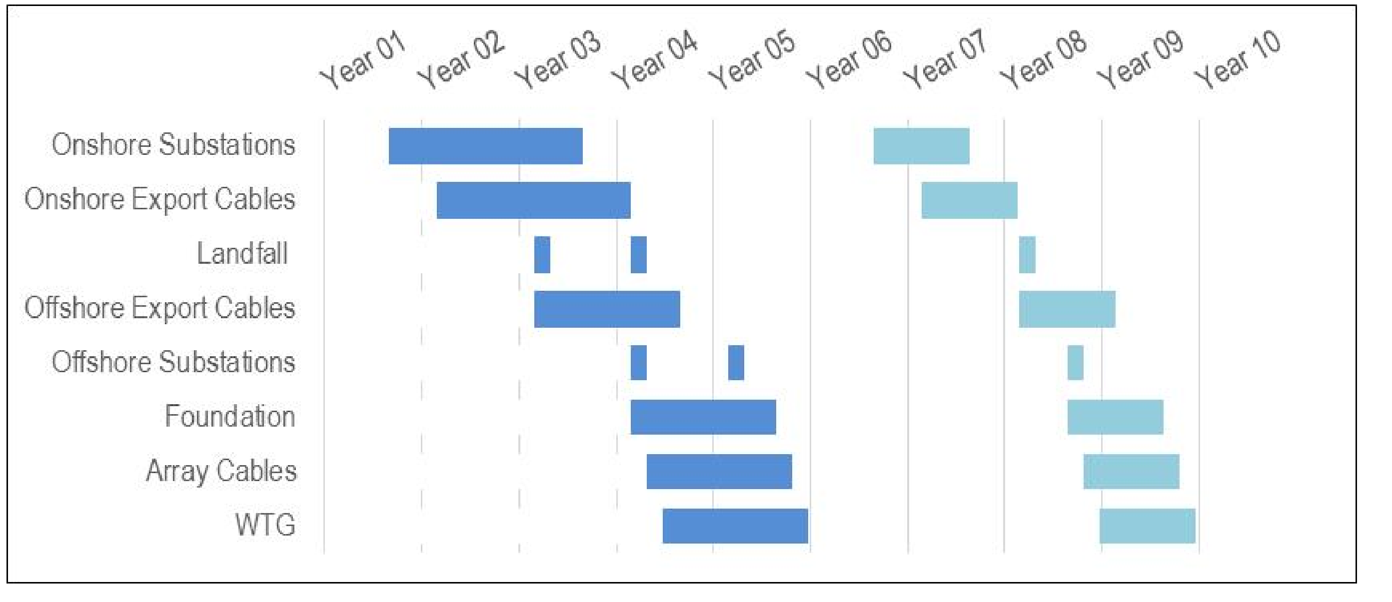


Figure 3.29: Indicative construction programme if project built out in two fully sequential phases.

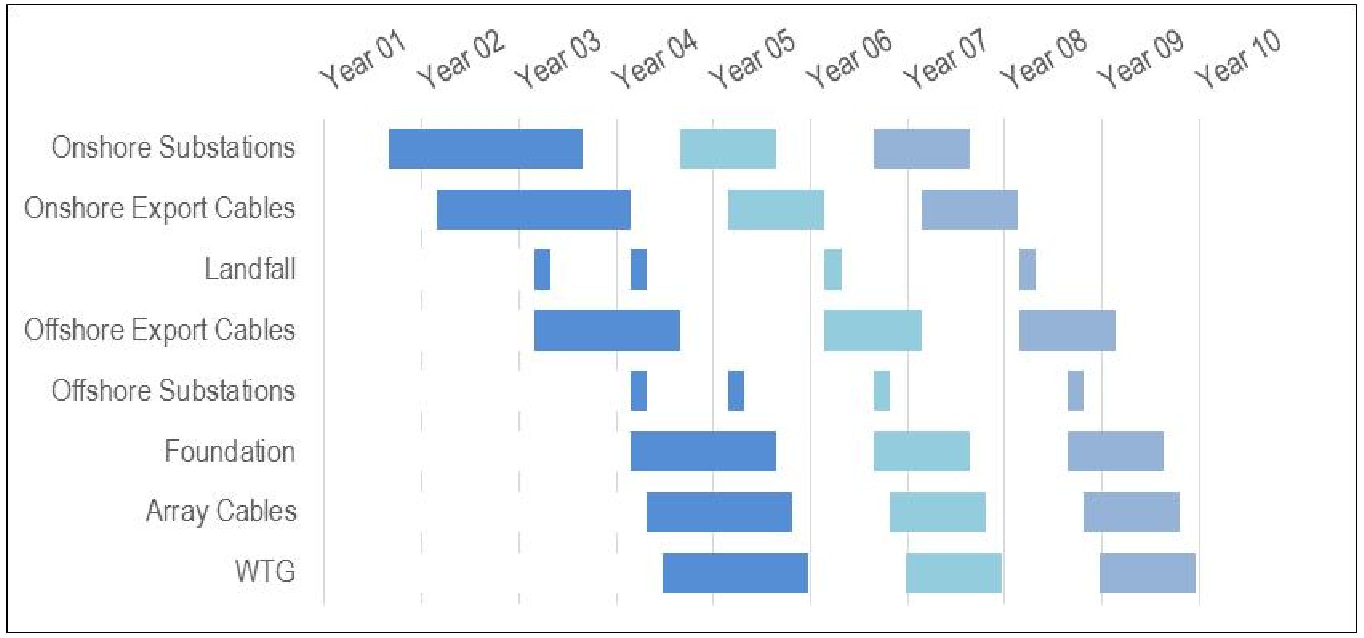


Figure 3.30: Indicative construction programme if project built out in three partially parallel phases.

3.8.1.5 Should Hornsea Three be built out in multiple phases (up to a maximum of three), it is possible that these phases could be constructed directly after one another but it is also possible that there may be gaps between the construction of the phases. There are various possible reasons for this including, for example, constraints in the supply chain or the requirements of the government's Contract for Difference process which offshore wind farms currently rely on to secure a price for the electricity produced by a project. Consideration of a range of possible influences suggests a maximum gap between the same project element in different phases (i.e. the end of piling of foundations for one phase and the start of piling of foundations on the next phase) of up to six years. However, this scenario is only considered likely where Hornsea Three is built out in two phases. If Hornsea Three were built out in three phases, the maximum indicative gap between the same component of Hornsea Three in different phases would be four years and this would assume that two phases were built out sequentially either before, or after, the gap to the third.

3.9 Operation and maintenance

3.9.1.1 The overall operation and maintenance strategy will be finalised once the operation and maintenance base location and technical specification of Hornsea Three are known, including turbine type, electrical export option and final project layout.

3.9.1.2 Maintenance activities can be categorised into two levels: preventive and corrective maintenance. Preventive maintenance will be undertaken in accordance with scheduled services whereas corrective maintenance covers unexpected repairs, component replacements, retrofit campaigns and breakdowns.

3.9.1.3 The Onshore operation and maintenance requirements will be largely corrective (because there is limited requirement for preventative maintenance on the onshore cables), accompanied by infrequent on-site inspections of the onshore export cables. However, the onshore infrastructure will be consistently monitored remotely, and there may be operation and maintenance staff visiting the onshore HVDC converter/HVAC substation and onshore HVAC booster station to undertake works on a regular basis.

3.9.1.4 The offshore operation and maintenance will be both preventative and corrective. The operation and maintenance strategy could include either an onshore (harbour based) operation and maintenance base, or a fixed offshore operation and maintenance base (offshore accommodation platforms). Alternatively, a Special Operations Vessel (SOV), could perform the function of an offshore accommodation base and Crew Transport Vessel (CTV). The final strategy may also be a combination of the above solutions.

3.9.1.5 The general operation and maintenance strategy may rely on CTVs, SOVs, offshore accommodation, supply vessels, and helicopters for the operation and maintenance services that will be performed at the wind farm. The maximum design scenario for the operation and maintenance activities can be found in Table 3.56 below. The total operational vessel and helicopter requirements for the offshore wind farm can be found in Table 3.57.

3.9.1.6 Preventive maintenance of subsea cables including routine inspections to ensure the cable is buried to an adequate depth and not exposed. The integrity of the cable and cable protection system (i.e., bending restrictors and bend stiffeners) will also be inspected. It is expected that on average the subsea cables will require up to two visits per year for the first three years before being reduced to yearly thereafter. Maintenance works to rebury/replace and carry out repair works on subtidal inter-array, platform inter-connector, accommodation power cables and export cables, should this be required.

3.9.1.7 No substantive maintenance is expected to be required on intertidal export cables. Temporary habitat disturbance in the intertidal as a result of periodic access requirements for cable inspections, including geophysical surveys. An indicative inspection regime could consist of one annually 'scheduled' inspection, plus further 'unscheduled' inspections following extreme events, such as large storms. Scheduled and unscheduled inspection activities will require a form of geophysical survey to be undertaken over the export cable route. This is likely to require two to three persons accessing the intertidal on foot or via small 4WD vehicle (low ground pressure vehicles will be considered such as an ARGO) for a duration of approximately 2-3 weeks."

Table 3.56: Maximum design scenario for operation and maintenance.

Parameter	Maximum design scenario
Operation and maintenance vessels - CTVs:	20
Operation and maintenance vessels - SOVs	4
Operation and maintenance vessels - supply vessels	Ad hoc
Helicopters: capacity (persons)	15
Jack-up vessels	Ad hoc
Onshore facilities area - offices (m^2)	2,500
Onshore facilities area - workshop and warehouse (m^2)	2,000
Harbour facilities – quayside length (m)	100
Operational hours	24 hours, 7 days a week
Total number of personnel	680
Parking facilities: cars	500
Road traffic: cars	500
Road traffic: trucks	100

Table 3.57: Maximum design scenario for offshore operation and maintenance activities. A single visit comprises a return trip to and from the offshore wind farm.

Parameter	Maximum design scenario
Helicopter wind turbine visits (per year)	4902
Helicopter platform visits (per year)	371
Helicopter crew shift transfer (per year)	780
Helicopter total trips (per year)	5273
Jack-up wind turbine visits (per year)	82
Jack-up platform visits (per year)	5
Jack-up total trips (per year)	87
Crew vessels wind turbine visits (per year)	2,433
Supply vessels accommodation platform visits (per year)	312

3.10 Repowering

3.10.1.1 Although the Crown Estate lease for Hornsea Three is 50 years, the design life of Hornsea Three is likely to be 25 years. During this time there may be a requirement for upkeep or reasonable improvement. Such maintenance is discussed in section 3.9 above, and will be provided for within the DCO. If there are changes in technology, it may be desirable to 'repower' Hornsea Three at or near the end of the 25 year design life of Hornsea Three (i.e. reconstruct and replace turbines and/or foundations with those of a different specification or design.). If the specifications and designs of the new turbines and/or foundations fell outside of the Maximum design scenario or the impacts of constructing, operation and maintenance, and decommissioning them were to fall outside those considered by this EIA, repowering would require further consent (and EIA) and is therefore outside of the scope of this document. At this time it is not expected that repowering would require any removal of existing or installation of new offshore or onshore cables.

3.11 Security

3.11.1.1 Hornsea Three will be suitably secured throughout all phases of development to ensure those working on Hornsea Three can work in safety and the supply of electricity to National Grid remains secure. Any above ground onshore infrastructure such as the onshore HVDC converter/HVAC substation and onshore HVAC booster station will be housed in secure gated compounds, as will any ongoing construction work. The onshore export cables are buried and will not be accessible from the surface. Any accessible parts such as the link boxes will be accessible only through secure manhole covers. The offshore infrastructure is by nature inaccessible due to being situated offshore.

3.12 Health and safety

3.12.1.1 All elements of Hornsea Three will be risk assessed according to the relevant government guidance as well as DONG Energy internal best practise. These risk assessments will then form the basis of the methods and safety mitigations put in place across the project life cycle.

3.12.1.2 DONG Energy has a focus on employee safety. DONG Energy's QHSE policy ensures that DONG Energy wind farms are safe by design and that the processes and procedures are adhered to. There is a clearly defined safety culture in place in order to avoid incidents and accidents.

3.12.1.3 There will be constant controls to ensure that the safety measures are observed and followed and Hornsea Three has built a safe workplace for its employees and contractors.

3.12.1.4 The focus on QHSE is intended to ensure that everyone feels safe, in a highly controlled and safety-driven environment. This is Hornsea Three's first priority. It is done by closely monitoring all matters relating to health and safety on our wind farms.

3.13 Waste management

3.13.1.1 Waste would be generated as a result of the project, with most waste generated during the construction of the offshore and onshore elements. In accordance with Government policy contained in NPS EN-1, consideration will be given to the types and quantities of waste that will be generated.

3.13.1.2 Procedures for handling waste materials will be set out in a Site Waste Management Plan (SWMP) which will be appended to the Environmental Statement as part of the final Application.

3.13.1.3 The SWMP will describe and quantify each likely waste type and record how it will be disposed of, reused, recycled or recovered in other ways during the construction stage of project. The SWMP will also describe the management arrangements for the different waste types and identify potential management facilities in the vicinity of the development. The available capacity of waste management facilities will be taken into account where applicable.

3.13.1.4 Estimates for waste types and arisings from the construction of the onshore and offshore components will be provided in the Site Waste Management Plan. These will be updated as further detailed design information becomes available prior to construction.

3.14 Decommissioning phase

3.14.1.1 At the end of the operational lifetime of the offshore wind farm, it is anticipated that all structures above the seabed or ground level will be completely removed. The decommissioning sequence will generally be the reverse of the construction sequence and involve similar types and numbers of vessels and equipment. TCE AfL for Hornsea Three requires that the project is decommissioned at the end of its lifetime. Additionally, the Energy Act (2004) requires that provides for a decommissioning plan must to be submitted to and approved by the Secretary of State for Business, Energy and Industrial Strategy, a draft of which would be submitted prior to the construction of Hornsea Three. The decommissioning plan and programme will be updated during Hornsea Three's lifespan to take account of changing best practice and new technologies.

3.14.2 Offshore decommissioning

Turbines

3.14.2.1 WTGs will be removed by reversing the methods used to install them.

Foundations

3.14.2.2 Piled foundations would likely be cut approximately 2 m below the seabed, with due consideration made of likely changes in seabed level, and removed. This could be achieved by inserting pile cutting devices. Once the piles are cut, the foundations could be lifted and removed from the site. At this time it is not thought to be reasonably practicable to remove entire piles from the seabed, but endeavours will be made to ensure that the sections of pile that remain in the seabed are fully buried.

3.14.2.3 Gravity base foundations could be removed by removing their ballast and either floating them (for self-floating designs) or lifting them off the seabed.

3.14.2.4 Any scour protection will be left in situ. Removal of scour protection is not reasonably practicable.

Offshore Cables

3.14.2.5 Currently there is no statutory requirement for removal of decommissioned cables and removing buried cables is difficult.

3.14.2.6 Exposed cables are more likely to be removed to ensure they don't become hazards to other users of the seabed. At this time, it cannot be accurately determined which cables will be exposed at the time of decommissioning. Although it is expected that most inter-array and export cables will be left in situ, for the purposes of the EIA it has been assumed that all cables will be removed during decommissioning, though any cable protection installed will be left in situ. Removal of cable protection is not reasonably practicable.

3.14.2.7 The removal of buried cables is not an operation for which there is much precedent. Therefore, at this time, it is difficult to foresee what techniques will be used. However, it is not unlikely that equipment similar to that which is used to install the cables could be used to reverse the burial process and expose them. Therefore, the area of seabed impacted during the removal of the cables could be the same as the area impacted during the installation of the cables. Divers and/or ROVs may be used to support the cable removal vessels.

3.14.2.8 Once the cables are exposed, grapples would be used to pull the cables onto the decks of cable removal vessels. The cables would be cut into manageable lengths and returned to shore.

3.14.2.9 Once onshore, it is likely that the cables would be deconstructed to recover and recycle the copper and/or aluminium and steel within them.

Landfall

3.14.2.10 To minimise the environmental disturbance during wind farm decommissioning the preferred option is to leave cables buried in place in the ground with the cable ends cut, sealed and securely buried as a precautionary measure.

3.14.2.11 Alternatively, partial removal of the cable may be achieved by pulling the cables back out of the ducts. This may be preferred to recover and recycle the copper and/or aluminium and steel within them.

3.14.3 Onshore decommissioning

Onshore export cable route corridor

3.14.3.1 To minimise the environmental disturbance during wind farm decommissioning the onshore cables will be left in place in the ground with the cable ends cut, sealed and securely buried as a precautionary measure.

3.14.3.2 The structures of the jointing pits and link boxes will be removed only if it is feasible with minimal environmental disturbance or if their removal is required to return the land to its current agricultural use.

Onshore HVDC converter/HVAC substation and onshore HVAC booster station

3.14.3.3 The components of the onshore HVDC converter/HVAC substation and HVAC booster station have varying life expectancies. Transformers typically have a useful life up to 50 years, and some components' lives can be extended beyond this period. The case for decommissioning the onshore HVDC converter/HVAC substation and HVAC booster station in the event of the wind farm being decommissioned will be reviewed in discussion with the transmission system operator and the regulator in the light of any other existing or proposed future use of the onshore HVDC converter/HVAC substation. If complete decommissioning is required then all of the electrical infrastructure will be removed and any waste arising disposed of in accordance with relevant regulations. Foundations will be broken up and the site reinstated to its original condition or for an alternative use.

3.15 References

CAP 393 – Air Navigation: The Order and the Regulations. August 2016

International Association of Lighthouse Authorities (IALA) 0-139 – The Marking of Man-Made Offshore Structures. December 2013.

CAP 437 – Standards for Offshore Helicopter Landing Areas. February 2013.