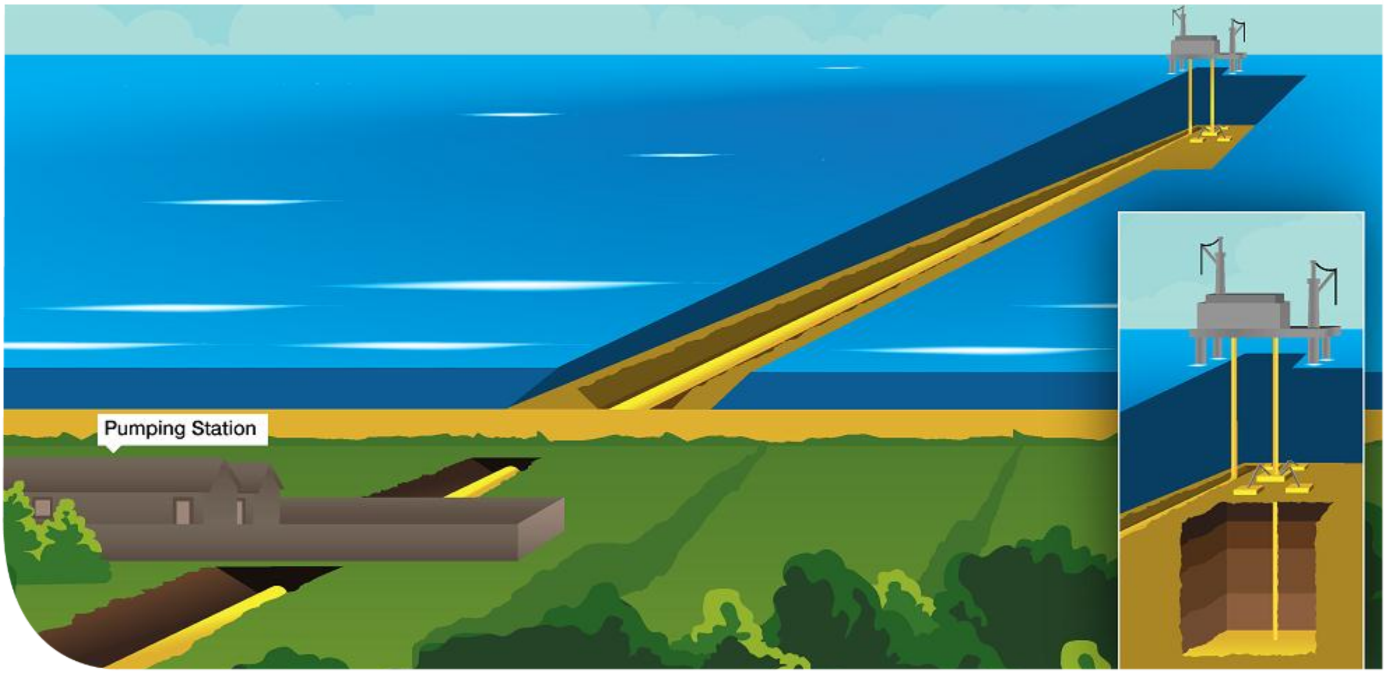
January 2016

K37: Offshore Infrastructure and Design Confirming the Engineering Design Rationale

Technical: Storage



Contents

Chapter	Title	Page
	Executive Summary	i
1	Introduction	1
2	Purpose	2
3	Project Overview	3
4	Offshore Infrastructure and Design	5
4.1	Platform	6
4.1.1	Platform Configuration	6
4.1.2	Topsides	8
4.1.2.1	Topsides Configuration	8
4.1.2.2	Topside Future Module	8
4.1.2.3	Topsides Structural Analysis	9
4.1.3	Substructure	9
4.1.3.1	The Jacket	9
4.1.3.2	Jacket Substructure Configuration	10
4.1.3.3	Foundations	10
4.1.3.4	Structural Analysis	10
4.1.3.5	Jacket Future Module	11
4.1.4	Import Riser	11
4.1.5	Fabrication	12
4.1.5.1	Materials	12
4.1.6	Future Expansion of Offshore Infrastructure	12
4.1.7	Transportation for Personnel	13
4.2	Offshore Pipeline	13
4.2.1	Offshore Pipeline Route Corridor	14
4.2.2	Mechanical Integrity	15
4.2.2.1	Design Criteria	15
4.2.2.2	Wall Thickness	15
4.2.2.3	Strength	15
4.2.2.4	Pipeline Stress	15
4.2.2.5	Pipeline Expansion	16
4.2.2.6	Pipeline Buckling Assessment	16
4.2.2.7	Pipeline Stability	16
4.2.2.8	Pipeline Spanning	16
4.2.2.9	Pipeline and Cable Crossings	16
4.2.2.10	Pipeline Fatigue Assessment	17
4.2.3	Connections	17
4.2.3.1	Risers and Tie-Ins Connections	17
4.2.3.2	Flanged Connections	17
4.2.4	Pipeline Protection	18
4.2.5	Pipeline Leak Detection	18
4.2.6	Materials and Coatings	18
4.2.6.1	Line Pipe	18

4.2.6.2 Pipeline Components 18
4.2.6.3 Pipeline Coatings 19
4.2.6.4 Insulation Joints 19
4.2.6.5 Anodes 20
4.2.7 PIG Operations 20
4.2.7.1 PIG Traps and Closures 20
4.2.8 Corrosion Management 20
4.2.8.1 Internal Corrosion 20
4.2.8.2 External Corrosion 21
4.2.8.3 Cathodic Protection 21
4.2.9 Construction 21
4.2.9.1 Fabrication and Installation 21
4.2.9.2 Testing 21
4.2.9.3 Operation Maintenance and Integrity Assurance Management 21
4.2.10 Pipeline Installation 21
4.3 Design Cases and CO_2 Composition 22
4.3.1 Captured Gas Composition 22
4.3.2 Optimum Composition 23
4.4 Offshore Processing & Storage Facilities 24
4.4.1 PIG Receiving Facilities 26
4.4.2 Wellheads and Trees structure definition 27
4.4.2.1 Wellhead 27
4.4.2.2 Christmas Trees 27
4.4.3 CO_2 Filters 29
4.4.4 CO_2 Injection Wells 29
4.4.4.1 CO_2 Import Valves 29
4.4.5 Utilities 30
4.4.5.1 Water Wash Treatment 30
4.4.5.2 Seawater Lift Pumps 32
4.4.5.3 Hydrate Inhibition 33
4.4.5.4 CO_2 Vent and Drains 33
4.4.6 Future Processes 34
4.4.6.1 Export 34
4.4.6.2 Produced Water 35
4.5 Support Systems 36
4.5.1 Power Generation 36
4.5.2 Control and Automation Philosophy 37
4.5.2.1 Hydraulic Control Packages 37
4.5.2.2 Communications 38
4.5.3 Material and Fluid Handling 38
4.5.4 Accommodation and Temporary Refuge 39
4.6 Safety Systems 39
4.6.1 CO_2 Toxicity 40
4.6.2 CO_2 Physical Properties 40
4.6.3 Fire and CO_2 Leak Detection 40
4.6.3.1 CO_2 Leak Detection 41
4.6.3.2 Emergency Escape 41
4.7 Venting Philosophy 42
4.7.1 Permanent and Temporary Vent Stacks 42
4.7.2 Depressurisation 43

4.7.3 Noise 43
4.7.4 Dispersion 43
4.7.5 Low Temperature 43
4.8 Effluent & Emissions Discharge Summary 44
4.8.1 Installation And Commissioning 44
4.8.2 Air Emissions 44
4.8.3 Liquid Effluents 45

5 Summary 46

6 Glossary 47

Key Words

Key Work	Meaning or Explanation
Carbon	An element, but used as shorthand for its gaseous oxide, carbon dioxide CO_2.
Capture	Collection of CO_2 from power station combustion process or other facilities and its process ready for transportation
First load	The amount of CO_2 produced during the first year of the CO_2 transportation system
Full chain	Reports described as “full chain” would cover the complete process from the capture of the carbon at the emitter plant to its injection into the storage reservoir
Key knowledge	Information that may be useful if not vital to understanding how some enterprise may be successfully undertaken
Storage	Containment in suitable pervious rock formations located under impervious rock formations usually under the sea bed
Transport	Removing processed CO_2 by pipeline from the capture and process unit to storage
Design Rationale	A design rationale is an explicit documentation of the reasons behind decisions made when designing a system

Executive Summary

This report is one of a series of reports; these “key knowledge” reports are issued here as public information. These reports were generated as part of the Front End Engineering Design (FEED) Contract agreed with the Department of Energy and Climate Change (DECC) as part of the White Rose Project.

White Rose seeks to deliver a clean coal-fired power station using oxy-fuel technology fitted with Carbon Capture and Storage (CCS), which will generate up to 448MW (gross) while capturing at least 90% of the carbon dioxide emissions. CCS technology allows the carbon dioxide produced during combustion to be captured, processed and compressed before being transported in dense phase to storage. The dense phase carbon dioxide will be kept under pressure while it is pumped through an underground pipeline to the seashore and then through an offshore pipeline to be stored in a specially chosen rock formation under the seabed of the southern North Sea.

This “key knowledge deliverable” (KKD) provides a summary description of the offshore infrastructure and design and confirms the engineering design rationale.

1 Introduction

National Grid Carbon Limited (NGCL) is a wholly owned subsidiary of the National Grid group of companies. Capture Power Limited (CPL) is a special purpose vehicle company, which has been formed by a consortium consisting of General Electric (GE), Drax and BOC, to pursue the White Rose (WR) Carbon Capture and Storage (CCS) Project (the WR Project).

CPL have entered into an agreement (the Front End Engineering Design (FEED) Contract) with the UK Government's Department of Energy and Climate Change (DECC) pursuant to which it will carry out, among other things, the engineering, cost estimation and risk assessment required to specify the budget required to develop and operate the WR Assets. The WR Assets comprise an end-to-end electricity generation and carbon capture and storage system comprising, broadly: a coal fired power station utilising oxy-fuel technology, carbon dioxide capture, processing, compression and metering facilities; transportation pipeline and pressure boosting facilities; offshore carbon dioxide reception and processing facilities, and injection wells into an offshore storage reservoir.

CPL and NGCL have entered into an agreement the Key Sub-Contract (KSC) pursuant to which NGCL will perform a transport and storage project (the WR T&S FEED Project) which will meet that part of CPL's obligations under the FEED Contract which are associated with the T&S Assets. The T&S Assets include, broadly: the transportation pipeline and pressure boosting facilities; offshore carbon dioxide reception and processing facilities, and injection wells into an offshore storage reservoir.

A key component of the WR T&S FEED Project is the Key Knowledge Transfer process. A major portion of this is the compilation and distribution of a set of documents termed Key Knowledge Deliverables, of which this document represents one example.

2 Purpose

The purpose of this document is to provide a summary and description of the offshore infrastructure and design and to describe the rationale behind the engineering design, describing the choices, reasons and configuration of the major equipment packages.

This document provides details of the:

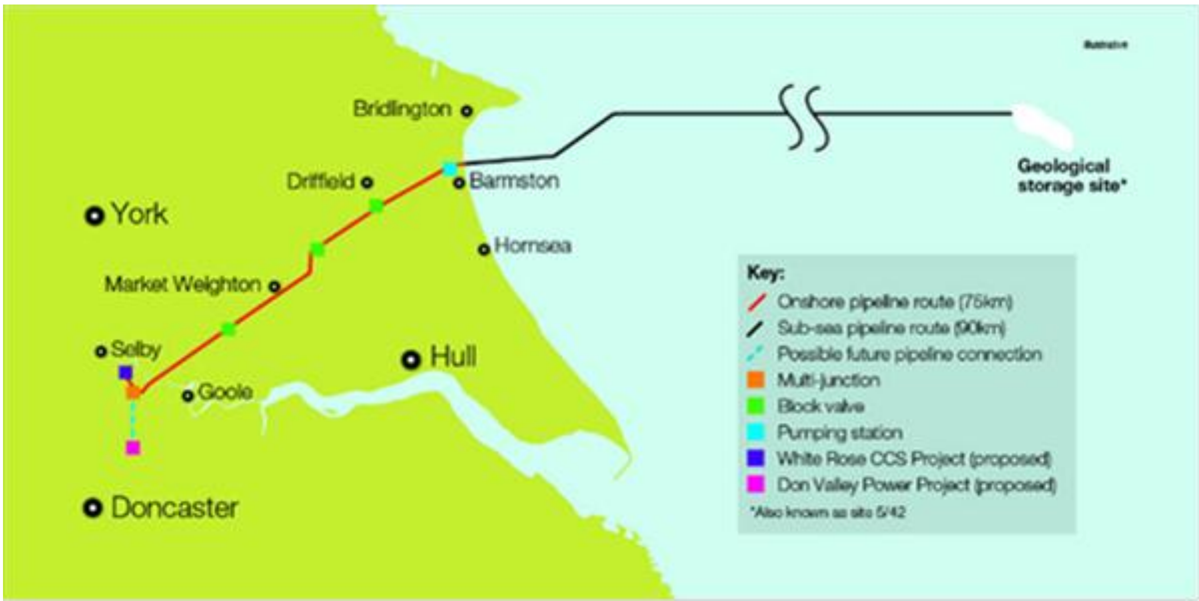
- platform design life including any requirements in the post-injection plan;
- a description of the design approach and configuration;
- a description of the planned extent of manning;
- a description of the means of transportation for personnel;
- a process description of the storage facilities including offshore infrastructure, subsea facilities, number and type of wells;
- a description of the control and performance monitoring systems including safety instrumentation and metering systems;
- a description of the injection manifold functional requirements;
- a description of riser type, connections and support configuration;
- pipe-work material grades and topside valve functional specifications;
- Topsides structural analysis (at FEED level);
- Topside injection tree description;
- a description of the venting philosophy;
- specification of CO_2 including impact of impurities;
- a description of CO_2 leak detection equipment;
- a description of novel items including required scale-up and previous experience;
- a description of the utilities;
- fabrication and installation summary;
- offshore injection facilities cathodic protection summary; and
- a description of normal and extreme load cases.

3 Project Overview

The White Rose CCS Project is to provide an example of a clean coal-fired power station of up to 448MW gross output, built and operated as a commercial enterprise.

The project comprises a state-of-the-art coal-fired power plant fully equipped CCS technology. The plant would also have the potential to co-fire biomass. The project is intended to prove CCS technology at a commercial scale and demonstrate it as a competitive form of low-carbon power generation and as an important technology in tackling climate change. It would also play an important role in establishing a CO_2 transportation and storage network in the Yorkshire and Humber area. Figure 3.1 below gives a geographical overview of the proposed CO_2 transportation system.

Figure 3.1: Geographical overview of the transportation facility

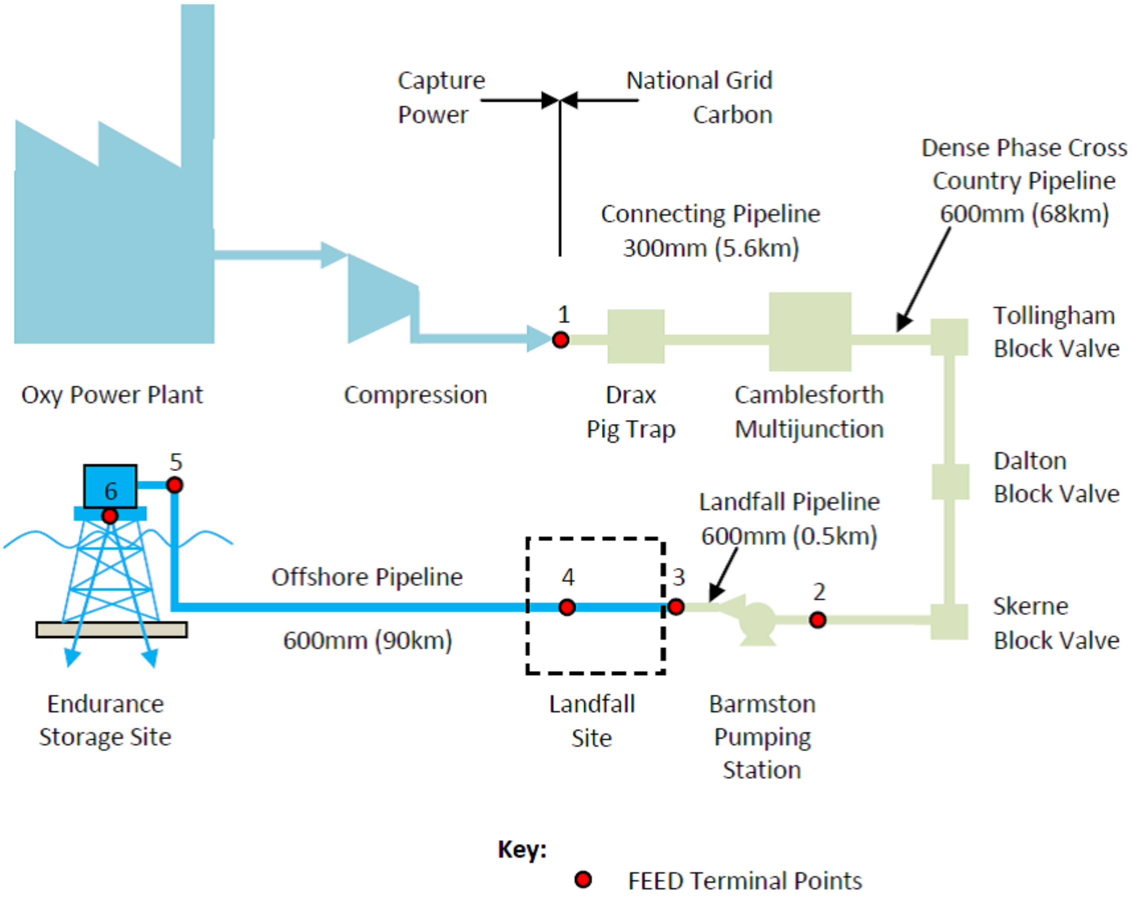


The standalone power plant would be located at the existing Drax Power Station site near Selby, North Yorkshire, generating electricity for export to the Electricity Transmission Network (the "Grid") as well as capturing approximately two million tonnes (t) of CO_2, some 90% of all CO_2 emissions produced by the plant. The by-product CO_2 from the Oxy Power Plant (OPP) would be compressed and transported via an export pipeline for injection into an offshore saline formation (the Endurance Reservoir) for permanent storage.

The power plant technology, which is known as oxy-fuel combustion, burns fuel in a modified combustion environment with the resulting combustion gases being high in CO_2 concentration. This allows the CO_2 produced to be captured without the need for additional chemical separation, before being compressed into dense phase and transported for storage.

The overall integrated control of the End-to-End CCS chain would have similarities to that of the National Grid natural gas pipeline network. Operation of the Transport and Storage System would be undertaken by NGCL. However, transportation of carbon dioxide presents differing concerns to those of natural gas; suitable specific operating procedures would be developed to cover all operational aspects including start-up, normal and abnormal operation, controlled and emergency shutdowns. These procedures would include a hierarchy of operation, responsibility, communication procedures and protocols. Figure 3.2 below provides a schematic diagram of the overall end-to-end chain for the White Rose CCS Project.

Figure 3.2: End To End Chain Overall Schematic Diagram



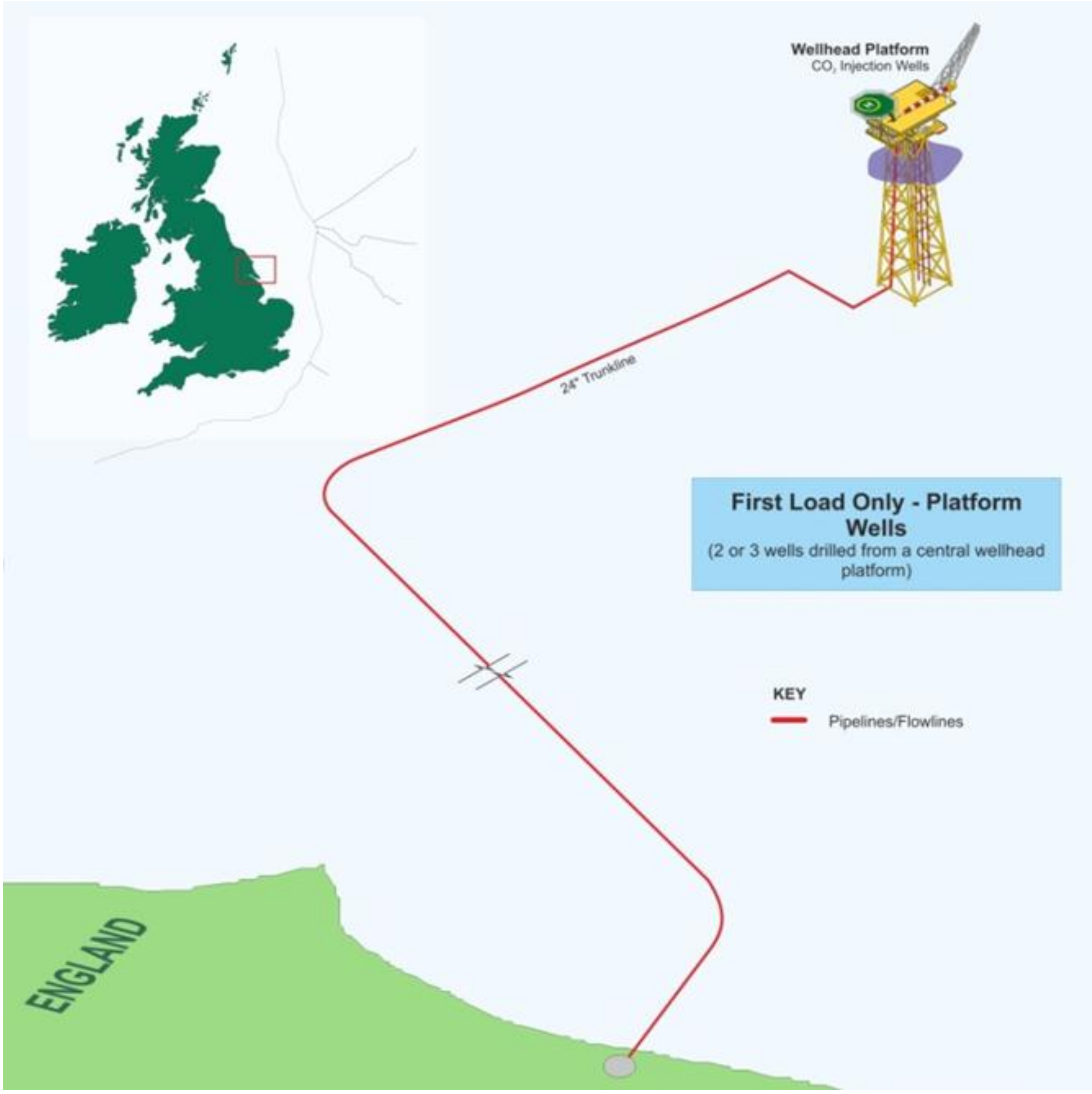
The geological storage site and the offshore platform facility at point 6 on Figure 3.2 have been named “Endurance”; they were previously referred to as “5/42”.

4 Offshore Infrastructure and Design

Captured CO_2 would be routed offshore through a subsea pipeline to a wellhead injection platform located at the reservoir. It would arrive through a 600mm (24in) nominal diameter riser then it would be processed and routed through an injection manifold into three platform injection wells.

The platform would be designed to accommodate a future expansion of the CO_2 injection capacity with a total of six well slots.

Figure 4.1: Platform Schematic



4.1 Platform

4.1.1 Platform Configuration

The selected concept is a fixed four leg jacket offshore wellhead platform, sitting in 59.3m of water and which will be a Normally Unmanned Installation (NUI) with production equipment and facilities, called the topsides, supported by a fixed four legged steel jacket substructure fixed to the seabed by eight skirt piles; two per corner leg.

The CO_2 would be received through a 600mm riser then fine filtered and routed to an injection manifold, which would supply three metered platform injection wells.

The platform would be designed to accommodate the first load of CO_2 as well as future loadings from multiple CO_2 emitters with a 'hang off' module and the expansion capability to allow onward transportation of CO_2 to other storage and Enhanced Oil Recovery (EOR) sites. The platform would initially have three wells for CO_2 injection, but a total of six conductor slots would be installed to allow further wells to be added at a future time.

Whilst three injection wells are specified for the first project load to allow for flexibility on the basis of the specified flow rate, work would be undertaken to formulate a multi-well design that would enable delivery of the flow rate variations with only two CO_2 injection wells.

The proposed offshore installation comprises:

- emergency overnight accommodation;
- Pipeline Inspection Gauge (PIG) receiving facilities;
- CO_2 filters;
- injection manifold;
- metering facilities on individual CO_2 injection well lines;
- CO_2 injection wells;
- utilities;
- support systems: crane, temporary safe refuge, battery room, marine navigation aids, telecoms and helideck;
- safety systems: fire and CO_2 gas detection systems, helideck foam system, firefighting and survival craft; and
- water disposal caisson.

The facility would have a forty year design life for fatigue and corrosion. Some facilities subject to obsolescence, such as control systems may have a shorter design and require upgrade or replacement.

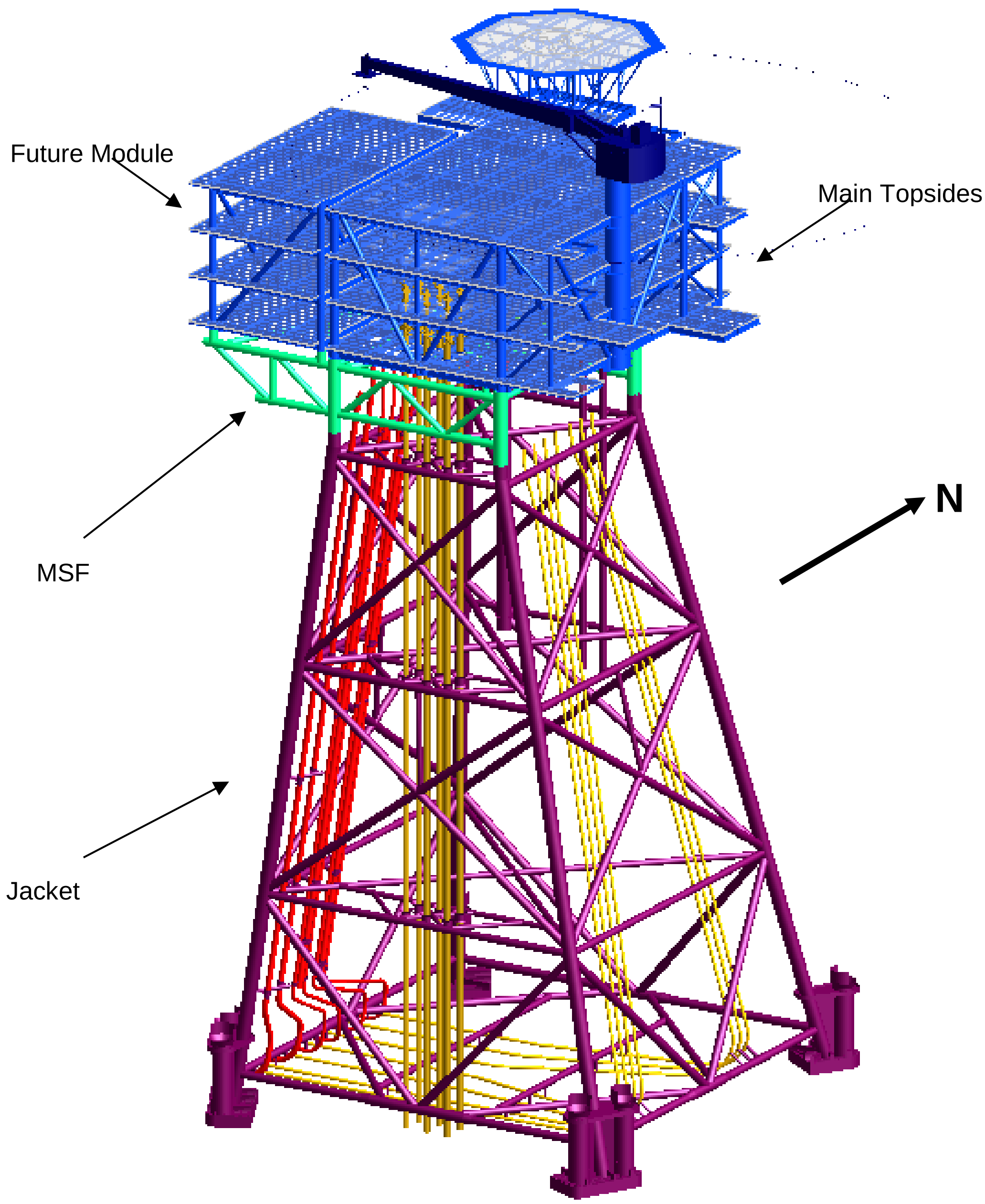
Whilst the platform is an uninhabited/unmanned installation, emergency accommodation would be provided for personnel required on the platform to support operation and maintenance duties.

Personnel required on the platform to support maintenance activities would be primarily transported by helicopter.

The location for the helicopter base and re-fuelling facilities would be considered. The impact of the proximity of the Smart Wind licence area on the helicopter approach to the platform would also be considered.

During water wash operations or maintenance campaigns a "walk to work" system from a vessel may be employed. The platform design would allow for landing of a gangway and provide stair access to the gangway.

Figure 4.2: White Rose Platform



4.1.2 Topsides

The topsides would be built a deck at a time with equipment provided by specialist manufacturers and designed to save maximum weight and space. It is envisaged that the completed platform would be loaded onto a conventional flat bottomed barge and towed to the reservoir.

It is envisaged that the future hang-off module would be installed in a single lift.

4.1.2.1 Topsides Configuration

The topsides are comprised of main topsides and a future module. It is to be a four-level structure comprising weather, upper and lower mezzanine and cellar deck. A Helideck is located above the weather deck. The majority of equipment is situated on the Cellar Deck with major units of piping on the Mezzanine Decks. There is sufficient space on the Weather Deck for wire lining equipment and associated mast.

Both main topsides and future module will be lift-installed with padeyes on each of the four corner legs.

The topside structure initially comprises a single lifted unit complete with helideck and platform crane. The structure has four levels and stabs into the Module Support Frame (MSF) on a 20m by 26m footprint. The topsides will have the following facilities:

- wellheads and manifold;
- temporary safe refuge and Local equipment rooms;
- temporary water wash package;
- MEG injection system;
- helideck with firefighting facilities;
- platform crane;
- power generation;
- fuel and fresh water bunkering;
- chemical injection;
- seawater lift pumps;
- PIG trap;
- control system;
- CO_2 and fire detection;
- life rafts and a TEMPSC; and
- wireline equipment (temporary equipment).

4.1.2.2 Topside Future Module

In addition, future facilities such as CO_2 booster pumps and future PIG traps will be contained in a future module which will impose additional loads on the MSF structure, Jacket and piles. The structure of the offshore platform will be configured to fit with the equipment plot plans and meet all the functional requirements of the structural recommended practice.

4.1.2.3 *Topsides Structural Analysis*

The topsides arrangement, described above, has been analysed for the following conditions using the Bentley SACS (structural design and analysis software) Version 5.6 v8i suite of programs:

- In-place;
- Loadout;
- Transportation; and
- Lift.

Redundancy analyses have not been considered since the risk to a major loss of primary structure due to a possible CO_2 cold splash will be mitigated by way of providing thermal protection to all members local to likely spillage locations. The weight of the thermal protection has been accounted for. Thermal protection will be specified during detailed design by the EPC contractor. Additional analyses to be undertaken during detail design should include:

- all local secondary and tertiary design;
- crane pedestal fatigue design;
- dropped object design; and
- helideck design.

4.1.3 Substructure

The substructure would be a conventional four leg jacket, typical for Southern North Sea hydrocarbon operations. It would be designed using current offshore design practice considering the 100-year return and 1-year return environmental conditions from two orthogonal and one diagonal approach directions. Deck elevations would be specified such that topsides structures and facilities are above the predicted 10,000-year return wave crest elevation.

4.1.3.1 *The Jacket*

The jacket will be lift installed, typical for Southern North Sea operations. The jacket foundation consists of six 72in diameter piles with an embedment length of 56m. The legs on Frame 1 have two piles each and the legs on Frame 3 have a single pile each. Early site surveys anticipate hard ground and if driven piles are not feasible then drilled and grouted piles are likely to be more appropriate. This will be confirmed during detailed design.

The jacket will house the following appurtenances:

- 1 x 24in CO_2 Import riser;
- 1 x 24in CO_2 Export riser (spare);
- 2 x 16in CO_2 Injection riser (spare);
- 2 x 16in Produced Water risers (spare);
- 5 x 12in J-Tubes for control and 2 x 12in J-Tubes for power supply;
- 1 x 1500mm Caisson for produced water disposal ; and
- 2 x 500mm Seawater lift caisson.

The riser and J-tube routing is designed to suit the positions in the topsides and subsea layouts. The positions of the caissons match the topsides layout. Pump and produced water caissons are vertical.

The MSF will be installed after the jacket installation and made ready to support the main topsides and future module.

The jacket would consist of steel tubular sections welded together to produce a support frame for the platform. Steel members in the splash zone would have extra thickness and the remaining jacket, piles, conductors and appurtenances would be protected by aluminium alloy sacrificial anodes located on the pipeline and jacket.

4.1.3.2 Jacket Substructure Configuration

The primary framing of the jacket was generally developed to cater for interfaces with the topsides, appurtenances, risers, caisson and J-tube layout and for transportation and installation restrictions.

4.1.3.3 Foundations

The jacket foundation consists of six 72in diameter piles with an embedment length of 56m. The legs on Frame 1 have two piles each and the legs on Frame 3 have a single pile each.

The jacket is connected to the foundation via shear plates and pile sleeves with a grouted connection at each pile. The pile sleeves are located to ensure that there is adequate clearance between the pile hammer and the jacket during installation.

4.1.3.4 Structural Analysis

The Jacket gross weight (exclusive of the MSF) is assessed as 2930t with 1400t of piles and the MSF installation weight is assessed as 326t. The main topsides module installation weight is assessed as 2990t while the future module installation weight is assessed as 1595t. The not to exceed (NTE) topsides weight was set as 5250t for the jacket analyses. In all cases the above values closely correlate to the White Rose Platform weight report values.

The following analyses were carried out for the design of the jacket and piles:

- In place;
- Loadout;
- Lifting;
- Transportation;
- On-bottom Stability;
- Fatigue;
- Boat Impact;
- Redundancy; and
- Pushover.

Additional analyses to be undertaken during detail design should include:

- full lift point design including trunnion releases;

- grout line support design including grout manifold support design;
- possible mitigation for jacket levelling requirements;
- all temporary platforms for sling laydowns etc.; and
- vortex shedding check for conductors, caissons and risers.

4.1.3.5 Jacket Future Module

The jacket would be pre-fitted with its CO_2 pipeline 600mm import riser as well as spare risers and J-tubes to facilitate future expansion including:

- one 600mm spare export riser, designed for 200barg dense phase CO_2, to allow export of CO_2 to other CO_2 storage or EOR sites;
- two spare CO_2 injection well risers, designed for 200barg dense phase CO_2, to connect the platform to future CO_2 injection sites;
- two spare water production well risers, designed for 50barg to connect the water production wells to the hub platform; and
- spare J-tubes for:
- control and power supply to future CO_2 injection wellheads;
- control and power supply for future water production wells;
- power supply cable from shore for future CO_2 booster pumps; and
- control and power supply to a new CO_2 reservoir.

4.1.4 Import Riser

Dense phase CO_2 will arrive at the platform through a 600mm import riser. The riser would be a fixed pre-installed rigid riser on the jacket with a minimum of 3D (3 x Diameter) bends with the riser and spool connections would be made by diver assisted connections (flanges).

Note that the use of 3D instead of 5D bends is specified to save space on the platform.

Support guides would be located along the length of the riser and a dead weight support installed above the sea level where the topside piping starts. An anti-corrosion coating is applied to the riser along its entire length to protect against external corrosion. An additional coating would be specified in the splash zone.

A maintenance valve and topsides pipeline riser ESDV would be provided to enable isolation of topsides from the pipeline in the event of an emergency. A bypass line would be provided around the maintenance valve for pressurisation at start up, in order to open the valve safely. Pressure and temperature indication would be available upstream and downstream of the ESDV, to facilitate leak detection.

Trapped CO_2 may be subject to change in ambient conditions and solar heat gain creating a thermal expansion. To address this, thermal relief valves would be provided between valves and self-venting ball valves would be used within the cavity. Valves are full bore and temperature instrumentation is non-intrusive to permit PIG operations without damage to the instrumentation. Integral double block and bleed valves would be provided for instrumentation isolation to save space on the platform.

The total CO_2 mass arriving at the platform would be computed by measuring the flow rate at each injection well together with their associated pressures and temperatures.

4.1.5 Fabrication

The platform topsides, jacket and piles are a conventional design familiar to offshore fabrication yards. The topsides and jacket would undergo structural analyses for the major installation and operating conditions including extreme storm and supply boat impact. The substructure and topsides would be fabricated separately.

4.1.5.1 Materials

The materials selection would be based on candidate material corrosion risk, mitigation and management options. They have been assessed in terms of their technical suitability, design life, operational limitations, availability, ease of fabrication and service performance of materials, inspection and corrosion monitoring possibilities and the operational benefits associated with limiting the number of different materials.

The CO_2 arriving at the offshore facility is essentially dry with minimal impurities. The primary approach to the mitigation of internal corrosion of the pipelines, equipment and associated piping would be to ensure that the dense phase CO_2 stream remains dry throughout. Materials selection assumes that there would be no free water present in the process systems and blowdown would be controlled to limit the minimum temperature within the processing system to -46°C. Given the potential low temperatures during depressurisation it is likely that conventional carbon steel would not be a suitable material.

An evaluation of the impact of escaped CO_2 or depressurising operations on the ductile/brittle behaviour of carbon steels has been made and the potential requirement for materials with enhanced low temperature properties has been evaluated. Based on these studies the selected materials for the pipeline, equipment, valves and pumps handling CO_2 at temperatures between -46°C and +50°C is low temperature carbon steel.

For operational regimes such as venting where the temperature of the materials would drop below -46°C, austenitic stainless steels UNS S31600/S31603 have been selected for relief valves, thermal stand-off pipes and vent piping.

Dense phase CO_2 has the ability to diffuse into many elastomeric materials which are generally employed for sealing equipment such as valves and flanges; consequently thermoplastic materials such as PTFE would be used for valve packing and seals.

4.1.6 Future Expansion of Offshore Infrastructure

The transportation and storage system is designed to create a hub to reduce incremental costs for future entrants into the pipeline, allowing capacity for future expansion beyond the initial CO_2 first load supply. To support this approach key expansion decisions have been taken:

- the 600mm pipeline has a capacity of approximately 17 Million Tons Per Annum (MTPA), which is well in excess of first load supply of 2.65MTPA and the 10MTPA expected maximum injection capacity of the reservoir.
- the platform would be designed to allow for future expansion of the CO_2 injection system; this includes:
- spare well slots to allow for additional CO_2 injection wells within the reservoir;
- a spare export riser would allow for future onward transportation to other CO_2 storage and EOR sites;

- a weight allowance would be provided in the platform jacket structure to allow installation of a future hang off module to house electric driven CO_2 booster pumps and a spare J-tube would be provided for a future import power cable;
- spare risers and J-tubes would be included in the jacket to allow for future CO_2 and water production well tie-backs to maximise the reservoir storage capacity;
- space for future PIG launchers/receivers would be allowed for in the design;
- space for an additional filtration vessel;
- other support processes such as MEG injection; and
- spare capacity would be included in the control systems for future CO_2 injection wells and water production wells.

Future CO_2 injection and water production well locations for expanded operations would be clarified and the number, size and pressure rating of future risers and J-tubes would be confirmed by subsurface modelling when the flow rates from expansion of storage operations beyond the first load are known.

A produced water discharge caisson would be provided to allow for water discharge from possible future water production wells. A seawater lift caisson would also be provided to supply seawater for water wash operations and other platform utility water requirements. A separate waste caisson would also be provided.

A dual hook crane vessel would lift and upend the jacket and place it standing on the seabed resting on pre-installed mud-mats.

The site survey and pipeline route survey have shown the ground to be hard, therefore potentially unfeasible for piling. So the eight piles are likely to be installed by drilling a hole for each pile then grouting the annulus between the soil and pile. The piles would be connected to the jacket pile sleeves by grouting before lift and placement of the topside module.

Conceptual studies have shown that the cost of providing an additional structural jacket weight bearing capacity for a future booster pump hang off module is small compared to providing a new future bridge-linked platform.

A substructure weight allowance of approximately 1500t would be provided to accommodate a future booster pump hang off module.

The power supply for future booster pumps would be provided by a new power cable from shore and a spare J-tube would be provided for the power cable.

4.1.7 Transportation for Personnel

Any personnel required to be on the platform to support maintenance activities will be transported via helicopter. If they are forced to stay overnight then accommodation is available as well as service water provided from tote tanks.

4.2 Offshore Pipeline

CO_2 would be routed through a 600mm (24in) nominal diameter pipeline from landfall to a wellhead injection platform located at the reservoir. It is approximately 90km in length. It would be designed in accordance with the Code of Practice for Subsea Pipelines. The subsea pipeline would run from the tie-in at the landfall on Barmston beach, to the tie-in on the offshore platform.

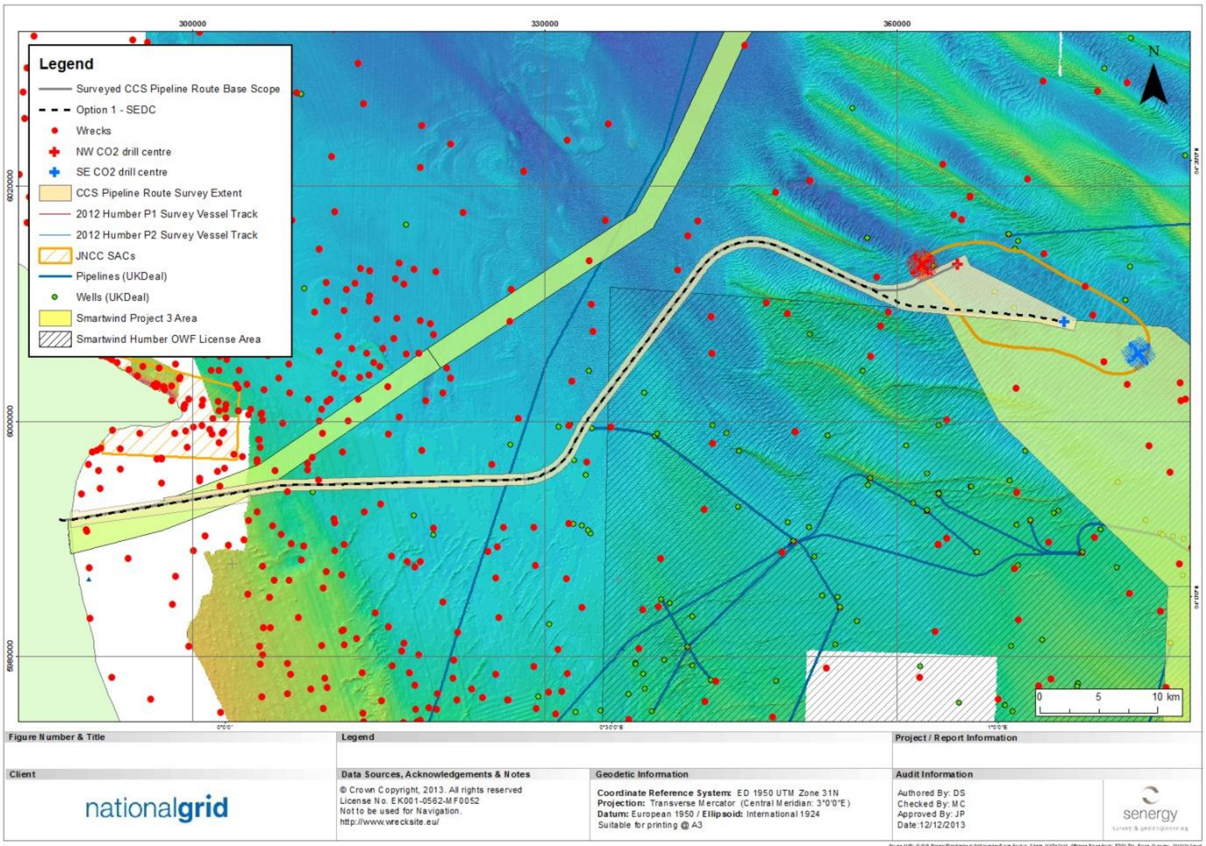
The design life of the pipeline system is 40 years. It should be noted that installation loads, platform movements and seismic loads would be considered as the design progresses. All information pertinent to the design has been considered to establish the design methodology for the offshore pipeline covering the key design components. The information can be broadly grouped into the following categories:

- Mechanical Integrity;
- Connections;
- Protection;
- Materials and Coatings;
- Corrosion Management; and
- Construction.

4.2.1 Offshore Pipeline Route Corridor

Offshore, 90km pipeline route corridor between landfall and the storage site where the water depth is in the range from 50m to 60m has been defined and surveyed. It is shown in Figure 4.3 below.

Figure 4.3: Offshore Pipeline Route Corridor



4.2.2 Mechanical Integrity

4.2.2.1 Design Criteria

Nominal pipe thickness has been selected using standard pipe sizes. Minimum wall thicknesses have been calculated for stress based design, to satisfy pressure containment, collapse, propagation buckling and local buckling. Reeling criteria has not been considered since reel-lay is not achievable given the pipeline diameter.

4.2.2.2 Wall Thickness

The wall thickness of finished bends has been selected to provide the minimum required wall thickness at any location of the bend. The outside diameter of the pipe would be 610mm with a wall thickness of 24mm.

The offshore pipeline wall thickness selected is primarily based on pressure containment requirements. An increased wall thickness is selected for the section of the route, which is routed over the sand waves, due to the pipe overstressing which is caused by large imperfection heights of the sand waves. The spool wall thickness would be increased to match the riser wall thickness, which increases the safety within the platform area and decreases the pipe buoyancy.

Pipeline wall thicknesses have been selected to withstand the Maximum Allowable Operating Pressure (MAOP). The maximum expected CO_2 fluid temperature in the offshore pipeline has been determined and temperature profiles have been used in pipeline design calculations.

The minimum pressure for normal operation is 90barg and the MAOP is 182 barg at low tide. A safety margin of 110% of the MAOP has been allowed for the maximum pressure, which the system can experience during a short time, limited by safety devices; this gives a Maximum Incidental Pressure (MIP) of 200barg.

A High Integrity Pressure Protection System (HIPPS) would be provided to protect the offshore pipeline from CO_2 booster pump pressures at the Barmston pumping station. Emergency Shut Down Valves (ESDVs) would be located at the pumping station at Barmston for shutdown and isolation of the offshore pipeline at the offshore platform.

4.2.2.3 Strength

The design factors used are compliant with *PD 8010-2 2004: Code of Practice for Pipelines: Subsea Pipelines*.

4.2.2.4 Pipeline Stress

Hoop, longitudinal and combined stresses, for fully restrained and straight pipe, has been calculated. The thin wall formula has been used to determine hoop stress within the pipe. Stress check calculations have been carried out using the Von Mises Criterion for the full design temperature and pressure range (using this information an engineer can say his design will fail, if the maximum value of Von Mises stress induced in the material is more than strength of the material).

The pipeline is compliant with the required CO_2 pipeline design codes to meet process design conditions and all integrity checks have been performed using stress-based design checks.

AutoPIPE stress software has been used to account for flexibility and stress intensification caused by fittings including bends. Stress based integrity checks have not been performed for the offshore pipeline design, but may be considered in future design stages.

4.2.2.5 Pipeline Expansion

Expansion analysis has been performed using strain-based equations to determine the location of the virtual anchor points from the platform end of the pipeline and calculate the magnitude of pipeline end expansion. The calculations account for MAOP and thermal loads in the pipeline and the cumulative resistance force between the pipeline and seabed. Leak test conditions are also assessed.

The end expansion is accounted for in the tie-in spool design which is designed to be flexible enough to absorb end expansion loads and to prevent excess transfer of loads into the riser.

4.2.2.6 Pipeline Buckling Assessment

Buckling assessment has been performed accounting for nominal wall thickness, ovality and the weight contribution of concrete coating, looking at:

- local buckling;
- propagation buckling; and
- restrained pipe buckling due to axial compressive forces.

Upheaval buckling analysis has been performed for a range of seabed imperfection heights to assess both the integrity of the pipeline and the propensity of the pipe to buckle. Any required mitigation methods have been identified.

All selected materials have an adequate low temperature toughness to prevent brittle fracture during normal operation and in blowdown conditions. Note that blowdown is a type of venting which releases the fluid, which is being transported, as a gas from a pipeline to atmosphere.

4.2.2.7 Pipeline Stability

The required concrete weight coating to ensure a stable offshore pipeline has been calculated, with consideration given to both lateral and vertical stability. An on-bottom stability analysis has also considered marine growth, environmental and soil conditions.

Pre-lay and post-lay trenching has been considered in areas where the excessive concrete coating is required to ensure offshore pipeline stability.

4.2.2.8 Pipeline Spanning

The allowable span lengths for free-spanning pipe have been assessed for both inline and cross-flow vortex induced vibration. Free spans along the route have been determined in an on-bottom roughness analysis and static analyses have been performed with the maximum allowable equivalent stresses.

4.2.2.9 Pipeline and Cable Crossings

A minimum separation of 0.3m would be achieved between pipeline and cable crossings by using separation mattresses with a thickness of 0.3m. Consideration has been given to the 1100mm (44in)

Langeled pipeline. Mattress protection would allow sufficient clearance between the Langeled pipeline and the bottom of the 600mm CCS pipeline.

Consideration has also been given to the two High Voltage Direct Current (HVDC) cables planned for the Forewind wind turbine array areas in the Dogger Bank Zone. If they are laid prior to the pipeline, they would be trenched and buried with protection mattresses laid over the cable location to ensure a minimum separation from the CCS pipeline. If they are laid after installation of the CCS pipeline, the pipeline would be in a trenched section and the HVDC cables would be laid over a pre lay mattress to ensure that the minimum separation is met.

To avoid interference of cathodic protection systems there would be no anodes over crossings, instead double anodes can be placed prior to and after the crossing, if necessary.

Crossing angles would be as close to 90 degrees as feasible. However, the crossing angle of the Dogger Bank cable crossing may be as acute as 12 degrees; in this case additional protection mattresses would be laid to account for pipe lay tolerances for such a long crossing.

To protect the pipeline from trawler gear interaction, rocks would be laid at the crossings. Buckling at the crossing and free spans prior to rock dumping has been assessed.

4.2.2.10 Pipeline Fatigue Assessment

A design stage fatigue assessment for the pipeline system has been performed based on a daily allowable pressure (stress) range during the pipeline design life and on an allowable frequency for a depressurisation down to 90barg from MAOP. This provides a design life in excess of 40 years. A detailed fatigue assessment can be performed once the number of cycles for operation, shutdown and start-up are known.

4.2.3 Connections

4.2.3.1 Risers and Tie-Ins Connections

A preliminary design for riser and tie-in spools has been performed which takes into account pipeline end expansion for operation and leak test conditions, upper bound and lower bound soil sensitivities, mattress loads and environmental loading.

Vortex induced vibration of the riser has been assessed in addition to the spool stability and equivalent stress checks.

Loads on riser supports, guides and flanges have been extracted for support design and for flange capacity checks to be performed.

The riser design is considered preliminary as platform layout and orientations are continuing. Installation loads, platform movements and seismic loads would be considered in the next design phase.

4.2.3.2 Flanged Connections

The subsea flanges have been rated for sufficient pressure ratings of the pipeline system. Flanges would be selected based on the pressure ratings of the systems in accordance with the flange specification and data sheet.

Flange loads on the tie-in spool and riser have been determined in the spool and riser analysis and the acceptability of the loads shall be confirmed with flange manufacturers.

4.2.4 Pipeline Protection

A dropped object study has determined the required protection for the installation. Pipeline protection requirements and mitigations have been considered to cover possible causes of damage including:

- trawl gear impact;
- trawl pull over; and
- Trawl hooking.

Further investigation would be performed to determine if additional protection is required from potential sources such as:

- level of fishing intensity from trawling;
- presence of major shipping channels pass the route and anchor protection is required; and
- the effect of seismic activity.

4.2.5 Pipeline Leak Detection

Pipeline leak detection had been considered prior to FEED; however it was decided that it was not required. NGCL would carry out frequent inspections such as PIG inspection runs to detect any defects or reduction in pipe wall thickness to prevent small bore leaks from occurring. Any pin-hole leaks will be difficult to detect through leak detection systems.

In the event of a full bore rupture there are pressure transmitters located at the Barmston pumping station and the Endurance platform which would show rapid reduction in pressure especially given the limited line pack available in a dense phase CO_2 pipeline. Based on the research work carried out it has been shown that the risk of such failure is very low and the ability to detect a rupture or large leak where a population is present and at risk is high. The increase in the ability to detect a rupture or large leak by means of an automatic detection system is therefore small. This would result in a very small reduction of a very small risk hence the provision of such measures is not considered to be required.

4.2.6 Materials and Coatings

A FEED assessment of selected materials and coatings for the CO_2 pipeline has been made.

4.2.6.1 Line Pipe

The line pipe would be carbon steel of L450MO grade to BS EN ISO 3183 and the manufacturing method would be Longitudinal Submerged Arc Welding (SAWL).

4.2.6.2 Pipeline Components

The following have been considered for pipeline components:

- flanges would be selected based on the pressure ratings of the systems in accordance with the flange specification and data sheet;
- Studbolts would be in accordance with ASTM A320 of Grade L7 S3 and nuts to ASTM A194 of Grade 7S3;
- bend requirements would be in accordance with specified in the bends data sheet; and

- Gaskets would be of an octagonal type, suitable for subsea use and in conformance with ASME B16.20.

4.2.6.3 Pipeline Coatings

The external coating of the line pipe would be factory fusion bonded epoxy with compatible fusion bonded epoxy field joint coating. Coatings have been considered in the following coating specifications and data sheets:

- external corrosion coating: datasheet for fusion bonded epoxy coating of offshore line pipe and specification for fusion bonded epoxy coating of offshore line pipe;
- field joint coating: datasheets for field joint coating and specification for field joint coating; and
- Concrete coating: datasheets for concrete weight coating and specification for concrete weight coating and bracelet anode installation.

Concrete Weight Coating (CWC) is a plant applied coating developer to provide negative buoyancy, mechanical protection, and on bottom stability for submarine pipelines. The pipeline “on-bottom” stability would be performed using a 2-D balance calculation. The CWC thickness would be determined using high density CWC of 3450kg/m^3 as shown below in Table 4.1.

Table 4.1: Selected Concrete Thickness

Section	Water Depth Range [m]	OD [mm]	Wall Thickness [mm]	Thickness CWC [mm]	Burial Condition
1 – Landfall (the first 1.3 km)	0m to 7.5m	610	22.23	95	Pre-lay dredged and backfill
2 – Shore Approach (the next 15 km)	5.7m to 36m	610	19.05	95	Pre-lay dredged and backfill
3 – Shallow Depth (the next11 km)	36m to 49m	610	19.05	115	Post-lay trenched
4 – Flat (the next 19.2 km)	49m to 53.4m	610	19.05	160(2)	Exposed
5 – Sand Waves (the last 41.9 km)	49.1m to 60.6m	610	25.4(3)	145(2)(3)	Pre-swept

Over sections 4 and 5, if the pipe were to be fully buried, which would protect from or mitigate the effects of excessive marine growth, then concrete requirements would reduce to 75mm for the 61.1km (up to the platform. For section 5, the wall thickness would be increased from 19.05mm to 25.4mm in line with the on-bottom roughness analysis and CWC would then be reduced from 160mm to 145mm.

Over sections 4 and 5, the on-bottom roughness assessment indicated that the section of the pipeline route, which would be laid over the sand waves, would overstress the pipeline due to the large seabed imperfections. Therefore, the sand waves would be pre-swept prior to laying of the pipe to reduce span length, heights and the level of imperfections. Pre-sweeping the route would require the laying down of the pipeline to ensure that it remains within the swept section of the seabed.

4.2.6.4 Insulation Joints

The monolithic insulation joint for electrical isolation of differing cathodic protection systems have been considered and a specification and data sheet compiled.

4.2.6.5 *Anodes*

The installation of anodes has been considered, including coating removal for anode attachment, and gap infill, in specification for concrete weight coating and bracelet anode installation.

4.2.7 PIG Operations

A 600mm PIG launcher and receiver would be provided at the Barmston outlet of the pumping facility and on the platform respectively to allow intelligent PIG operations of the offshore pipeline for inspection and monitoring purposes.

The PIG launchers and receivers would be designed in accordance with PD-8010 and be of sufficient dimensions to fit Intelligent pipeline Inspection Device (IID), also known as an intelligent PIG.

All changes of internal diameter would be tapered to allow smooth running of the PIGs.

4.2.7.1 *PIG Traps and Closures*

The offshore platform PIG launchers and receivers have been considered in the offshore platform PIG launchers and receivers specification and data sheet.

4.2.8 Corrosion Management

Corrosion mechanisms and mitigation methods have been determined and include an assessment of:

- internal corrosion:
  - CO_2 corrosion;
  - dense phase CO_2 corrosion;
  - oxygen corrosion;
  - hydrogen sulphide corrosion/cracking; and
  - hydrates presence of impurities;
- external corrosion:
  - differential corrosion;
  - microbiologically influenced corrosion;
  - stress corrosion cracking; and
  - Galvanic attack.

4.2.8.1 *Internal Corrosion*

The primary approach to the mitigation of internal corrosion of the offshore pipeline, riser and tie-in spool is to ensure that dense phase CO_2 stream remains dry (free of water) throughout.

No internal corrosion is expected for the offshore pipeline as the pipeline is operated dry (free of water) and is protected by a high integrity water monitoring and shutdown protection system.

All water introduced after laying for pre-commissioning would be treated and inhibited.

4.2.8.2 *External Corrosion*

The primary corrosion control strategy would be the use of high quality factory and field applied coatings with the cathodic protection system as the secondary, but mandatory, protection system. The design life of permanent cathodic protection systems would be 40 years.

4.2.8.3 *Cathodic Protection*

The cathodic protection would be indium activated aluminium alloy bracelet anodes (Aluminium-Zinc-Indium). Cathodic protection of the offshore pipeline would be provided by bracelet sacrificial anodes designed in accordance with *BS EN ISO 15589-2:2014 Petroleum, petrochemical and natural gas industries; Cathodic protection of pipeline transportation systems; Offshore pipelines*.

4.2.9 Construction

The pipeline would be constructed from carbon manganese steel material grade national standard BS EN ISO 3183 Grade L450 (X65). The 600mm ND pipe would be manufactured using submerged arc welding techniques.

4.2.9.1 *Fabrication and Installation*

A high level philosophy for planning, alignment and co-ordination of the engineering, procurement, installation and construction activities has been developed.

4.2.9.2 *Testing*

Technical requirements related to the flooding, cleaning, gauging, strength testing, leak testing and pre-commissioning of the offshore pipeline facilities have been considered in the specification for offshore pipeline flooding, cleaning, gauging, testing and pre-commissioning.

4.2.9.3 *Operation Maintenance and Integrity Assurance Management*

An operating philosophy for the offshore storage facility has been developed which includes information on start-up, normal operation, shutdown and non-routine activities such as well intervention, PIG operations and maintenance. This would be further developed during the detailed design stage to ensure compliance with PD 8010-2.

4.2.10 Pipeline Installation

The pipeline size (600mm ND) and depth of water is ideally suited for using an S-lay barge to lay the offshore pipeline between. The pipeline installation would be initiated at the landfall and with the laydown at the platform. This would be performed by a single pipe-laying vessel with a low draft, which would allow it to approach the shore. Shallow water (less than 8m deep) extends to about 8km from the coast.

To initiate the pipe laying the pipe would be pulled ashore from the offshore based vessel. This would avoid additional onshore based works and the need for an onshore laydown area and would avoid the requirement of a shallow water tie-in.

The soil conditions at the landfall site consist of silty sand overlying Boulder clay and Cretaceous chalk. Direct pipe method was ruled out due to limitations in installable pipe diameter. Although the pipeline could be installed at the landfall using Horizontal Direct Drilling (HDD) or the micro-tunnel method, it would be installed using is a sheet piled cofferdam starting on the beach leading to an open-cut trench offshore. An onshore micro-tunnel upstream of the cliff face will terminate in the cofferdam on the beach.

4.3 Design Cases and CO_2 Composition

Throughout the design life of the CO_2 transportation system, the anticipated flowrates would increase, as the number of power plants and other emitters, which capture carbon using various technologies, become operational and start producing carbon dioxide for storage offshore. The CO_2 transportation network is expected to develop in overall production as detailed in Table 4.2.

Table 4.2: Predicted Development of CO_2 Transport System

Flow Case	Year 1 (First Load) MTPA	Year 5 MTPA	Year 10 MTPA
Design	2.68	10.0	17.0
Normal	2.31	10.0	17.0
Minimum	0.58	0.58	0.90

The ramp rates (the speed at which the flow could be increased) during normal operation would be 2% of the maximum flow per minute. Table 4.3 summarises the operational scenarios and the percentage full load where the transition (change over) is permitted.

Table 4.3: Capture Plant Ramp Rates

Status Of Capture Plant	Initial Operational Mode	Target Operational Mode	Transition (% Full Load)	Ramp Rate (% maximum flow per minute)
Start-Up	Air	Oxy	40 to 50 (Note 1)	2%
Normal	Air	Oxy	40 to 50 (Note 1)	2%
Shutdown/Trip	Oxy	Shutdown	100 to 40 (Note 2)	2%

Notes: 1 Assuming the plant made the transition to Oxy mode (from air to carbon capture) at 40% load, there would then be a period of time following the transition, during which there was no transportation flow, to allow the CO_2 purity to be established. This would be followed by a fairly rapid ramp up of the flow to 40% flow, at a rate determined by the speed that the control valve upstream of the OPP is programmed to open, followed by a ramp from 40% to 100% at 2% per minute, hence taking an half-hour.
2. During shut-down and plant trip the plant would ramp down from 100% to 40% at 2% per minute at which point the control valve at the OPP tie-in would close at the maximum practicable rate.

4.3.1 Captured Gas Composition

The objective, operationally, for the onshore transport system would be to maintain the CO_2 stream in the dense phase from the tie-in point with the Drax OPP through to injection wells offshore at the NUI. A first load composition for flow assurance modelling and equipment sizing has been defined. A generic oxy-fuel capture CO_2 composition, normalised for the removal of oxygen, is shown in Table 4.4 below:

It is currently anticipated that the First Load composition can be derived which contains 99.7% CO_2 and up to 10 ppmv of oxygen (O_2) and 50 ppmv of water (H_2O). The remaining balance of composition would be comprised of nitrogen (N_2) and Argon (Ar). This is a typical composition from an OPP such as Drax.

Table 4.4: Proposed Year 1 / First Load CO_2 Composition

Component	Volume %
CO_2	99.700
Ar	0.068
N2	0.226
O2	0.001
H2O	0.005

The Energy Institute published a guidance note on "Good Plant Design and Operation for Onshore Carbon Capture Installations and Onshore Pipelines", wherein the impacts of various components on pure CO_2 properties are documented.

Table 4.5 below lists potential contaminant components and their effect on the density and viscosity of pure CO_2.

Table 4.5: Contaminant Components and Their Effect on Pure CO_2 Properties

Component	Effect
SO_2	Increases density and viscosity
H_2S	Minimal effect
O_2	Decreases density and viscosity
N_2	Decreases density and viscosity; more than O2
H_2	Decreases density and viscosity; more than N2

4.3.2 Optimum Composition

Since small levels of impurities significantly impact the properties and phase envelope of pure CO_2, making it difficult to predict its behaviour over an anticipated operating envelope, an optimum composition needed to be developed.

The optimum composition to maintain the stream in the dense phase between the standalone power station and the offshore platform has been studied to develop a CO_2 transportation pipeline composition specification.

The CO_2 pipeline transportation system entry requirements were defined by NGCL. A composition Safe Operating Limit (SOL) has been calculated with a saturation pressure of no more than 80 barg for the CO_2 rich mixture along with the maximum allowable component levels.

The permitted limits for each component relative to safety design, integrity design and hydraulic efficiency criteria are summarised in the following Table 4.6 below.

Table 4.6: CO_2 Transportation System Entry Requirements

Component	Limiting Criteria (Volume %)		
	Safety Max	Integrity Max	Hydraulic Efficiency
CO_2	100	100	96
H_2S	0	0.002 (Note 1)	0
CO	0.2	0	0
NOx	0.01	0	0

Component	Limiting Criteria (Volume %)		
SOx	0.01	0	0
N_2	0	0	(Note 4)
O_2	0	0.001 (Note 2)	(Note 4)
H_2	0	0	(Note 4)
Ar	0	0	(Note 4)
CH_4	0	0	(Note 4)
H_2O	0	0.005 (Note 3)	0

Notes: 1. NACE limit for dense phase CO_2 at a total pressure of 150 barg. Specified to avoid a requirement for sour service materials
2. Maximum oxygen content (10 ppmv). Specified to any avoid material selection issues in the well tubing, where the dry CO_2 contacts saline aquifer water
3. Maximum water content (50 ppmv). Specified to ensure no free water occurs during normal or transient operations
4. The allowable mixture of non-condensable components in the CO_2 stream must be:
Gaseous Phase: $N_2 + O_2 + H_2 + CH_4 + Ar \leq 9.0\%$
Dense Phase: $N_2 + O_2 + H_2 + CH_4 + Ar \leq 4.0\%$, with H_2 no greater than 2.0%

The composition of the CO_2 would be expected to change beyond the first year of operation of the Drax OPP and the CO_2 transportation network, even if the only source of captured CO_2 is from an Oxyfuel technology power plant. To cover the possible range for the future operation of the CO_2 transportation system NGCL have proposed two compositions below in Table 4.7 to cover the possible range for the future operation of the CO_2 transportation system. This data may be fed into the computer simulation tool, HYSYS, to study the system and make predictions on how it will respond to various scenarios.

Table 4.7: Proposed Year 5 and Year 10 Future Transportation System CO_2 Compositions

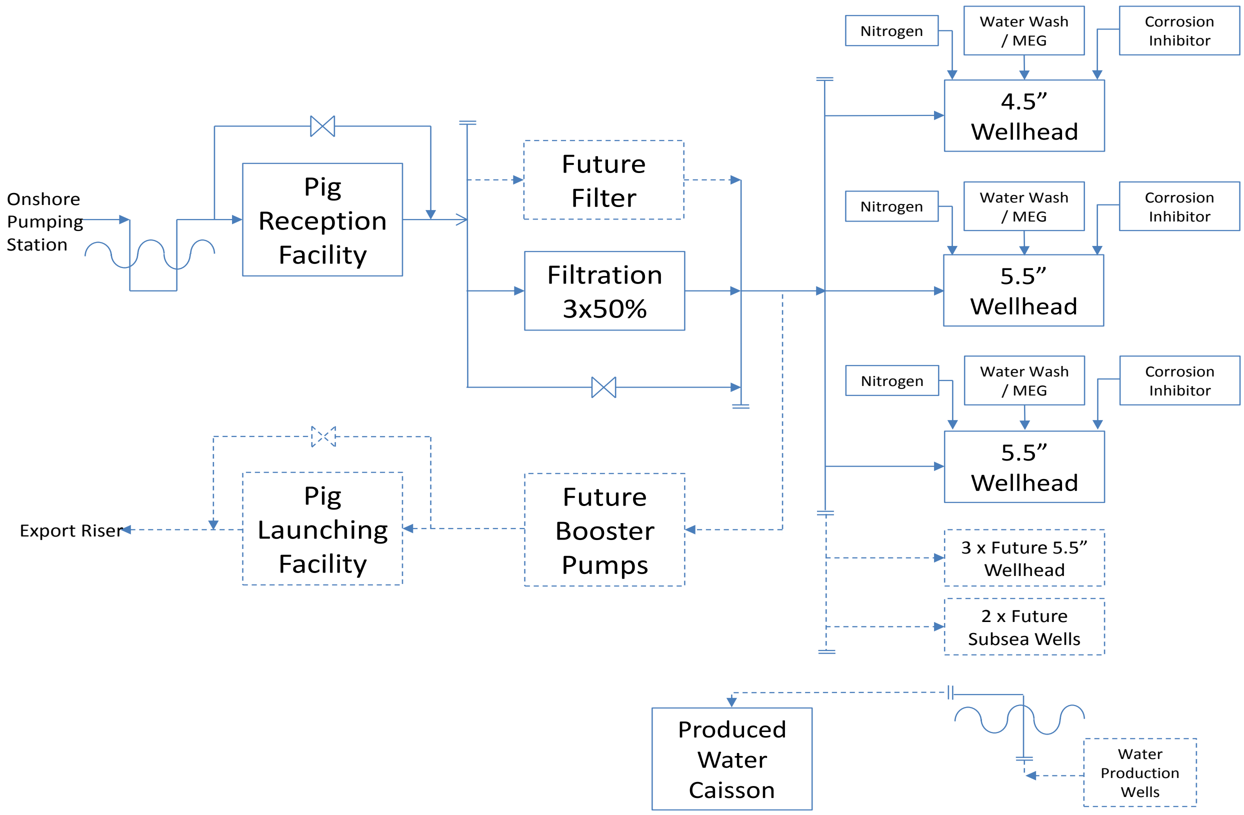
Component	Year 5 and 10/Future Generic Composition Volume %	HYSYS Year 5 and 10/Future Sensitivity Composition Volume % (Note 1)	Non-HYSYS Year 5 and 10/ Future Sensitivity Composition Volume % (Note 2)
CO_2	97.400	96.000	96.000
Ar	0.599	0.411	0.407
N_2	1.995	1.371	1.355
O_2	0.001	0.001	0.001
H_2O	0.005	0.005	0.005
H_2	0.000	2.000	2.000
H_2S	0.000	0.002	0.002
CO	0.000	0.200	0.200
NOx	0.000	0.010	0.010
SOx	0.000	0.010	0.010
CH_4	0.000	0.010	0.010

Notes: 1. The maximum specification for NOx and SOx is 100 ppmv each (0.01 vol%). However, these two particular components are not available for use in the GERG2008 fluid package specified for the HYSYS simulation work. These have therefore been omitted from the HYSYS composition for the purposes of steady state modelling. Note that HYSYS is an oil and gas process simulation software
2. The non-HYSYS composition specified would be used for any other simulation work required for the FEED, for example, Flow Assurance, and where the software permits the use of NOx and SOx.

4.4 Offshore Processing & Storage Facilities

The offshore storage processes are summarised in the following diagram:

Figure 4.4: offshore storage processes



The offshore storage facility of the overall White Rose Carbon Capture and Storage network is a Normally Unmanned Installation (NUI) wellhead injection platform. The platform comprises of the following:

- PIG receiving facilities;
- Cartridge type filters;
- Injection manifold;
- metering facilities (on individual CO_2 injection well lines);
- three CO_2 injection wells which dispose of the CO_2 into the saline aquifer storage site located in block 5/42 (Endurance) of the Southern North Sea. In the future, the number of platform injection wells can be increased, and the platform design shall include for an additional three future wells.
- utilities:
  - MEG storage and pumps to prevent CO_2 hydrate formation during well start-up and water wash operations;
  - water wash treatment facilities to avoid halite build up when CO_2 injection is shut-in (seawater lift pumps and caisson, filters and chemical treatment). Additional water wash facilities will be provided by a temporary skid (injection pumps, filters, power generation and chemicals);
  - other utilities (drain system, diesel storage system, nitrogen (quads), fresh water system, power generation system, seawater system, CO_2 vent, wellhead control panel);

- support systems (crane, temporary safe refuge, battery room, marine navigation aids, telecoms and helideck);
- safety systems (fire and CO_2 gas detection systems, helideck foam system, DIFFS and TEMPSC).
- water disposal caisson to allow disposal of produced water from injection aquifer (future requirement) and seawater cooling return line.

The design and operating conditions of the CO_2 processing facilities are summarised below:

Table 4.8: CO_2 Processing Facilities Design and Operating Conditions

Equipment	Design Conditions		Operating Conditions	
	Pressure (barg)	Temperature min/max °C	Pressure min/max barg	Temperature min/max °C
Inlet Filters	200 (Note 1)	-46/50	90/182 (Note 2)	1/20
Manifold	200 (Note 1)	-46/50	90/182 (Note 2)	1/20
Risers for Subsea Tie Backs	182 (Note 1)	-46/50	-	-
PIG Launchers for Subsea Tie Backs	182 (Note 3)	-46/50	-	-
Riser	182 (Note 3)	-46/50	90/182	1/20
PIG Receiver	200 (Note 4)	-46/50	90/182	1/20

Notes: 1. A design pressure of 200 barg is applicable to ASME B31.3 pipework sections only. The offshore pipeline and risers are designed in line with PD 8010-2:2004. Pipeline design pressure (MAOP = 182 barg) is the pressure at which calculations are based on for the pipeline. The maximum incidental pressure is 10% above this value; 200 barg.
2. Minimum operating pressure is set to ensure CO_2 remains within the dense phase throughout the transportation system. Maximum operating pressure is set at the maximum allowable operating pressure of the offshore pipeline.
3. The offshore pipeline and risers are designed in line with PD 8010-2:2004. The pipeline design pressure (maximum allowable operating pressure = 182 barg) is the pressure at which calculations are based on for the pipeline. The maximum incidental pressure is 10% above this value; 200 barg.
4. PIG Receivers are covered under PD 8010-2 code; however parts of the receiver (end closures) would be designed to PD 5500:2012. The whole receiver is designed under PD 5500:2012 (for testing purposes) with a design pressure set at the maximum incidental pressure of the offshore pipeline of 200 barg.

4.4.1 PIG Receiving Facilities

A PIG receiver would be provided on the platform to support PIG operations on the main pipeline. The dense phase CO_2 would arrive from shore at the permanent PIG receiver on the platform through the 600mm import riser.

The receiver would take delivery of the pipeline PIG from shore which has traversed the length of the pipeline to inspect and clean it. If required the PIG could accommodate an IID, designed for use in dense phase CO_2 and specified to seek any evidence of localised or general internal/external corrosion or damage to the pipe wall.

The pipeline would have a constant inside diameter to allow smooth transit of PIGs and bend radii compatible with running IID. At branched connections, guide bars would be incorporated where the diameters exceed 25% of the pipeline diameter to ensure effective and safe PIG operations. The deck space and structural weight capacity would be designed to facilitate the permanent PIG operations.

Personnel would be aboard the platform during PIG operation. All PIG receiver isolation valves above 450mm would be motorised to aid the opening and closing. A mechanical valve door interlock system would be provided for the PIG receiver isolation valves to ensure the correct safe valve sequencing takes place to protect personnel when opening the receiver door.

The throttling valve around the PIG receiver to the filters would be specified to have a minimum stop, creating an open path within the pipework and so minimising the quantity of thermal relief valves on the facility, thus reducing future maintenance and inspection regimes.

Surface temperature indication would be provided to monitor the pipework temperature during depressurisation to avoid extremely cold temperatures leading to brittle fracture. Future PIG requirements would be considered including:

- a 600mm PIG launcher in a suitable location to align with the spare 600mm CO_2 export riser supplying CO_2 to additional CO_2 reservoirs; and
- PIG launchers in suitable locations to align with spare CO_2 and water production risers supplying satellite CO_2 injection wells or receiving produced water from within the reservoir.

The design and operating conditions of the import facilities are summarised below.

4.4.2 Wellheads and Trees structure definition

The specification of wellheads and trees at FEED definition is described below.

4.4.2.1 Wellhead

It is envisaged that a standard design compact wellhead in “slim hole” configuration could be used for the standard platform wells. This would normally only be clad in sealing areas, however in this instance it would be worth cladding the bore between the tubing hanger seals and the wellhead seal surface for long term insurance against CO_2 migrating into the tree to wellhead void.

Note that a 10,000psi system may be required (dependant on the pressure test requirement for the completion. Should there be congestion of downhole function hydraulic lines, electric cables or fibre optic cables passing the body of the downhole safety valve, or just below the tubing hanger, it may be advantageous to use 10 ¾in casing below the surface wellhead down to safety valve depth.

Risks:

- Little new risk. Standard equipment and running procedures used.

4.4.2.2 Christmas Trees

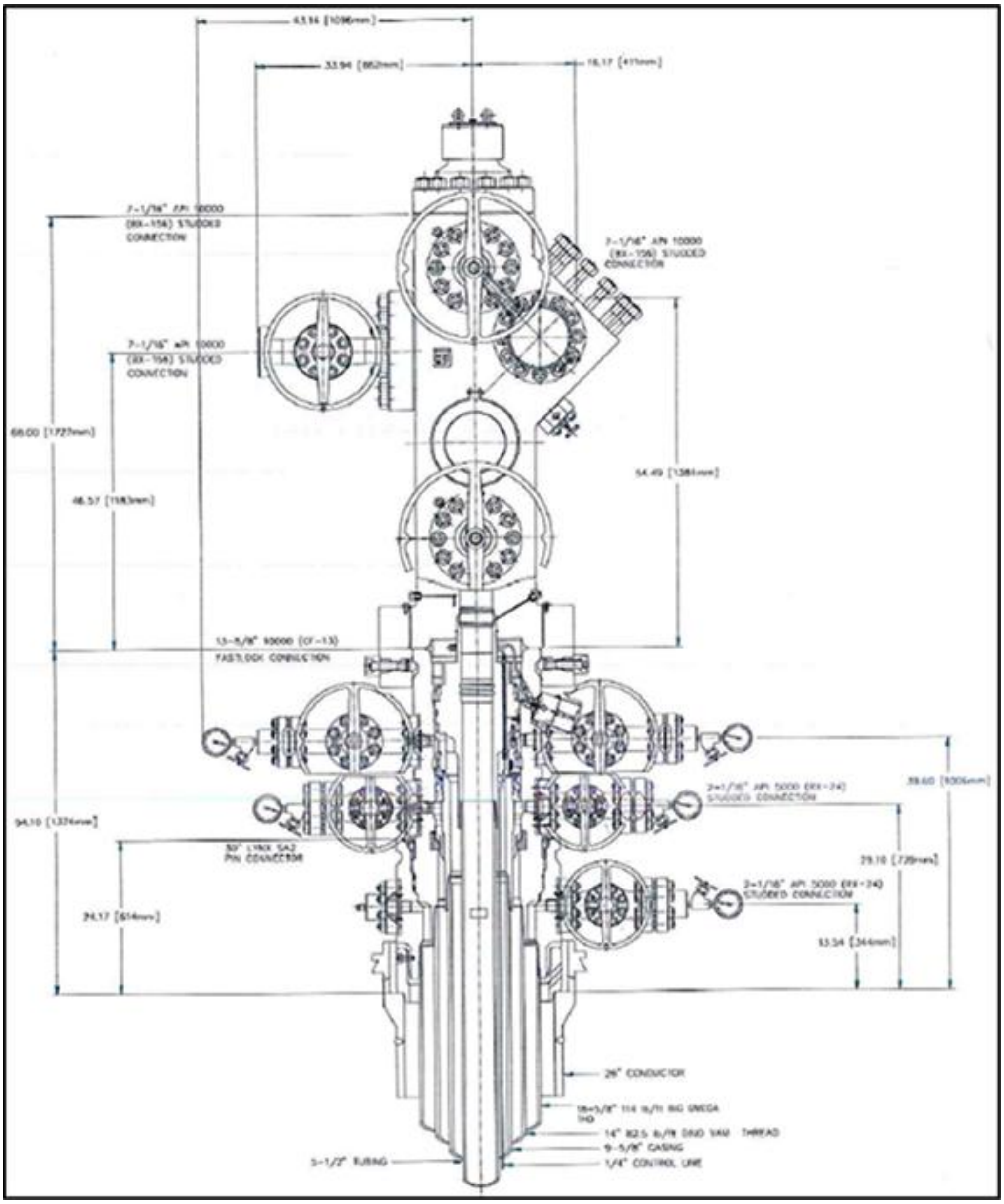
A 5⅛in 5,000psi working pressure conventional surface tree with standard valve configuration will be mounted after the upper completion has been installed. The 5⅛in bore is compatible with 5 ½in tubing.

The tubing hanger and wellhead would be ported for between four and six downhole feed-throughs which can be allocated for hydraulic, electrical or fibre-optic functions, as necessary. Redundant ports can be blank if not required. A conventional wireline plug profile would be machined into the tubing hanger bore and the premium tubing connection below. Wetted surfaces and other internal seal surfaces will be clad in CRA to mitigate corrosion potential due to water from water wash treatments.

Standard valve configuration will be used with manual lower master valve, remote actuated upper master, manual swab, remote actuated production wing and manual kill valve. The temperature rating for the tree will be API "L" (-46°C) or API "K" (-60°C). The technical difference being that the lower temperature "K" rated tree and tubing hanger would use metal-to-metal seals whereas the "L" tree and tubing hanger may use a combination of metal-to-metal and non-elastomeric seals.

Flow assurance and transient flow studies indicated that the minimum wellhead temperature will be approximately -20°C. The worst case exposure with respect to corrosion is expected at the base of the well where the provisional recommendation is for use of high chromium material (25% Cr) with a PREN greater than 40.

Figure 4.5: Schematic of a Typical Compact Wellhead and Injection Tree



4.4.3 CO_2 Filters

The dense phase CO_2 from the import pipeline is routed through fine filters which would be installed to remove particles in the CO_2 that may have been picked up in the offshore pipeline.

The reservoir would cope with particulates in the CO_2 stream if they are less than 10 microns; anything larger would need to be filtered out of the stream.

The CO_2 stream would be filtered through fine, disposable cartridge type filters; coarse screening filters may also be used upstream of the fine filtration. The filter design flow rate for the first load is 2.65MTPA.

The deck space and structural weight capacity would be designed to facilitate the initial requirement of three filter vessels and allow for future expansion to four filter vessels.

The filter package would be provided with a bypass and remote temperature, pressure and differential pressure monitoring facilities.

Venting facilities for the filters, connected to the CO_2 vent stack, would be provided for each filter to allow depressurisation. Removal of liquid CO_2 prevents the formation of solids within the vessel; it is likely that the vessel would be depressurised by draining liquid CO_2 from low points to the platform vent.

The three filter vessels would be designed so that each could accommodate 50% (5MTPA) of the total flow. This over sizing of the vessels would allow for efficient future expansion. The future expansion of four filter vessels would each accommodate 33.3% of the total flow of up to 10MTPA.

4.4.4 CO_2 Injection Wells

After filtering the CO_2 would be routed to an injection manifold which would supply three CO_2 injection wells to dispose of the CO_2 into the saline aquifer reservoir. The three wells accommodate the flexibility required for specified flow rate, but consideration would be given to a multi-well design that would enable delivery of the flow rate variations with only two CO_2 injection wells.

The number of injection wells can be increased; a total of six well slots are provided to allow for future expansion of CO_2 injection capacity. The design would accommodate this expansion with a manifold configured to have three spare blanked tees or sufficient deck space to extend the manifold in the future.

Table 4.9: Configuration of Well Slot

Well Slot Description	Number of Wells Required
Initial First Load CO_2 Injection wells	3
Spare well slots /manifold tie ins for future CO_2 injection wells or re-drills	3

The CO_2 injection wells would be individually metered and comprise two 140mm tubes and one 114.5mm tube; they would be hard piped to receive the following:

- Water Wash from a temporary water wash skid loaded onto the platform lay down area;
- nitrogen from quads loaded onto the platform lay down area; and
- Mono Ethylene Glycol (MEG) from storage and injection pumps for hydrate control.

4.4.4.1 CO_2 Import Valves

A Sub-Surface Isolation Valve (SSIV) would be installed on each wellhead and would be included in the design suitable for dense phase CO_2 with the specified contaminants.

A 600mm pipeline riser ESDV and inboard riser ESDV would be provided suitable for dense phase CO_2 with the specified contaminants.

A pipeline backpressure control valve would be provided to ensure the pipeline backpressure remains in dense phase, above 90 barg, at all times.

4.4.5 Utilities

The following utilities would be provided on the platform:

- MEG storage tanks and injection pump;
- drain system;
- diesel storage system;
- nitrogen (quads);
- fresh water system;
- power generation system;
- seawater system;
- CO_2 vent; and
- wellhead control panel.

The two key services, for which the utilities are required, are water wash treatment facilities and hydrate inhibition.

4.4.5.1 Water Wash Treatment

When CO_2 injection is shut in, the saline aquifer water slowly returns to the near well bore region, replenishing the salt which had been displaced by the CO_2. Halite (rock salt) is gradually deposited near the well bore at a rate proportional to the frequency and duration of injection well shut-in.

Subsurface modelling has confirmed that water wash treatment is required for each CO_2 injection well to avoid halite build-up.

Water wash activities would be likely to require chemical injection, in particular biocide, oxygen scavenger and corrosion and scale inhibitor.

The platform design would incorporate a lay down area suitable for temporary water wash facilities, along with a permanent platform seawater lift pump with associated power generation to supply water to the water wash facilities.

The specification for the water wash is summarised in the table following:

Table 4.10: Injection Well Water Wash Data

Water Wash Specification	Data
Water Wash Rate	1000m^3/day per well
Water Wash Duration	7 days per well

Water Wash Specification	Data
Water Wash Frequency	Annually Injection Well Water Wash Data
Wash Medium	Filtered Seawater
Filtration Specification	Filtration levels have been provided for budget quotes of <10 microns
Water Treatment	Biocide Oxygen scavenger Corrosion inhibitor Scale inhibitor

Temporary water wash facilities including all required equipment with integrated diesel power generation are widely available for rental from drilling service contractors.

The equipment required for a temporary water wash skid includes:

- Seawater Lift Pump;
- Basket Filter;
- Cartridge Filter;
- Chemical Injection and Storage;
- Water Booster Pump;
- Water Injection Pump;
- Power Generation; and
- Nitrogen Quads.

The skid facilities include chemical tote tanks and pumps for chemical injection to the wash water.

A nitrogen quad would be required to provide a gas cap on the well to increase the tubing head pressure of the well after water wash activities.

A permanent seawater lift pump and caisson with anti-fouling protection would also be provided on the platform. The seawater lift and water wash connections to the wells (water wash, MEG, and nitrogen) would be hard piped to the lay down area with isolation valves.

The temporary equipment is all portable so would be transported to and from shore by supply vessel and lifted to the lay down area on the platform by crane.

The total weight of the water wash skid has been approximated, excluding the weight of nitrogen quads:

Table 4.11: Approximate Weights of Temporary Water Wash Equipment

Equipment Description	Weight (kg)
Engine Skid	10000
Pump Skid	10000
Cartridge Unit 10 microns	2000
Cartridge Unit 6 microns	2000

Chemical Injection Pump/Tanks	10000
Tank 100 barrels	25000
Total	**59000**

4.4.5.2 Seawater Lift Pumps

Two seawater lift pumps within individual seawater lift caissons would be required to supply the temporary water wash skid and platform utility water for first load and future users. The caissons would have a screen to protect the pump, stop divers from inadvertently entering the caisson and stop the pumps from falling to the seabed. An anti-marine growth lining would discourage fouling when the pump is not in use. Biological growth would be minimised within the caissons by copper and aluminium anodes fed with an electric current from the biofouling control package.

The seawater lift pumps would have the following features:

- capable of supplying the required water wash rate for a single well of at least 1000m^3/day;
- provision of platform utility water (for deck wash down and intermittent use);
- supply of cooling water for the future CO_2 booster pumps recycle cooler;
- electro-chlorination package to prevent inlet fouling;
- anti-fouling facilities on the inlet to discourage fouling when not in use; and
- facilities for shock dosing of Sodium Hypochlorite.

The delivery pressure from the seawater lift pumps would be aligned with the requirement of the temporary water wash skid injection pumps to ensure the required net positive suction head is achieved.

The seawater lift pumps would be provided with a vent/vacuum breaker at the top of the riser to prevent surge/water hammer upon start up and to prevent vacuum conditions as the seawater drains down the riser when the pump has stopped.

The lift pumps would be provided with a variable speed drive for smoother start up and lower starting current.

The seawater from the lift pumps would be filtered to a maximum of 80 microns by filters before entering the distribution header. Coarse filtration is specified because fine filters would be provided within the temporary water wash package when injection to the wells takes place. The level of coarse filtration would be defined based on the tolerances associated with the future CO_2 booster pumps recycle cooler. Differential pressure indication with a high-level alarm is provided for process monitoring and maintenance.

The design and operating conditions of the sea water lift facilities are summarised below:

Table 4-12 Sea Water Lift Facilities Design and Operating Conditions

Equipment	Design Conditions		Operating Conditions	
	Pressure (barg)	Temperature min/max (°C)	Pressure min/max (barg)	Temperature min/max (°C)
Sea Water Pumps	15	-10/50 (Note 1)	5 to 10	4 to 19
Sea Water Lift Caisson	atm		atm	4 to 19

Equipment	Design Conditions		Operating Conditions	
Sea Water Lift Pumps Filter	15	-10/50 (Note 1)	5 to 10	4 to 19

Notes: 1. Design temperature set at black body limit and matches all process and utility systems. The maximum operating temperature foreseen at the outlet of the future CO_2 booster pumps recycle cooler is 26°C.

4.4.5.3 Hydrate Inhibition

During normal operation, the CO_2 in the pipeline and topsides facilities would be dry and so there would be no risk of hydrate formation, but there are some operational scenarios where CO_2 could contact water and form hydrates:

- at the base of the well;
- at the top of the well; and
- during initial start-up and start-up following well water wash operations.

There is only a small likelihood of hydrate formation at the base of the well, as the temperature there is in excess of the hydrate formation temperature when the beneficial effect of formation brine salinity is taken into account. Depending on the well materials selection, particularly at the base of the well where the CO_2 would contact saline water, permanent corrosion inhibitor injection facilities could be required until the aquifer water in the near well bore region had been displaced.

There would also a small likelihood of hydrate formation at the top of the well where aquifer water may migrate to the top of the CO_2 tubing column after a prolonged shutdown of the well. This is not a likely scenario as the aquifer water is denser than CO_2; however, convection currents from the reservoir could drive water up the column where water would dissolve in the dense phase CO_2 over time.

The highest risk of hydrate formation is during well water wash operations to remove halite build up. The CO_2 would be displaced from the well seawater which is used to remove halite build up from the vicinity of wellbore. After completion of operations, CO_2 would displace the wash water.

MEG has been selected over methanol as the optimum hydrate inhibitor during well water wash operations when dry CO_2 comes into contact with seawater, as methanol is prone to enhance the drying out effect which leads to salt precipitation in the near well bore region. Study work has shown that a MEG concentration of 57% w/w is required to prevent hydrate formation in the CO_2 injection wells. MEG and methanol were compared with the following results:

- methanol is a flammable and toxic substance and special care is required in storage and usage, while MEG is non-flammable and has lower oral toxicity; and
- methanol has severe salting-out effects compared to MEG; when injected to the saturated aquifer, methanol is likely to exacerbate halite precipitation in the formation. Solubility of salt (NaCl) in MEG is far higher than in methanol, and so, MEG is less likely to cause halite precipitation to occur.

4.4.5.4 CO_2 Vent and Drains

A fully rated CO_2 vent would be provided capable of venting both the platform topsides and the onshore and offshore pipelines.

Depressurisation of the 600mm pipelines would be controlled to ensure that solids do not form in the equipment and that excessively low temperatures do not occur in the pipelines. Provisional depressurisation modelling of the offshore pipeline suggests this would take around fifteen days to complete. Metering of the CO_2 vent would also be required so pipeline depressurisation could be managed.

An alternative methodology for the preferred method of removing CO_2 from the pipeline was considered during the conceptual design using high pressure dry air to displace the CO_2 into the injection wells. The air could then be depressurised from the pipeline via the vent without constraint on depressurisation rate. Alternative methods of depressurising the pipeline would be considered further.

High level dispersion modelling covering the range of depressurisation flow rates has been completed to ensure safe conditions for platform personnel during venting operations, this would be confirmed. Flow assurance modelling and actuation philosophy for venting would be defined fully.

Platform facilities containing CO_2 will, where possible, be vented using low point drains. Removing liquid CO_2 from vessels or pipework prevents solid CO_2 forming internally once the pressure drops below the triple point at around 5 barg.

A small drains vessel would be provided for platform slops with the facility to discharge it to a supply vessel.

Spill prevention would be required with specific provision of bunds, sealed deck for fuel and chemical storage/transfer areas on the platform. Specific spill provision requirements would apply to the temporary water wash skid.

4.4.6 Future Processes

4.4.6.1 Export

During the first load CO_2 would not be exported from the platform. However by year 10 it is anticipated that the reservoir would have reached capacity and CO_2 would need to be transported onwards to other CO_2 storage or EOR sites. The platform would be designed to facilitate this future expansion.

A connection downstream of the CO_2 filters and upstream of the manifold would be provided for future CO_2 export. The future pumps would be sized for the full pipeline capacity of 17MTPA and would consist of three 50% variable speed offshore CO_2 booster pumps which would increase the flow pressure to 182 barg; this assumes an additional offshore pipeline would be installed. A flow controller would look at the onshore transport system flow rate and flow into the existing reservoir. Mechanical HIPPS valves are envisaged on the pumps common discharge to protect the pipeline from overpressure in the event of a blocked discharge. Manual venting facilities to the CO_2 vent stack would be provided on low points on the pump discharge pipework to permit maintenance activities to be carried out.

A recycle line would route the CO_2 to a cooler. A shell and plate type exchanger has been selected due to the high design pressure on both sides of the exchanger for gasket integrity and the compactness of the design.

Downstream of the booster pumps, the CO_2 would flow to the 600mm export riser.

Deck space is allowed for a future 600mm PIG launcher. A manual vent would be provided for venting the PIG launcher (from a low point to minimise low temperatures within the piping). An additional venting connection routed to the vent stack would be located upstream of the riser.

One spare J-tube would be pre-fitted for control and power supply to future satellite CO_2 injection wells outside the reservoir, and a further spare J-tube would be pre-fitted for a power supply cable from shore for the future offshore CO_2 booster pumps.

The design and operating conditions of the CO_2 export facilities are as follows:

Table 4-13 CO_2 Export Facilities Design and Operating Conditions

Equipment	Design Conditions		Operating Conditions	
	Pressure (barg)	Temperature min/max (°C)	Pressure min/max (barg)	Temperature min/max (°C)
Offshore Future CO_2 Booster Pumps	281.5	-46/50	144/182 (Note 3)	1/27
Offshore Storage Facility Future PIG Launcher	281.5 (Note 4)	-46/50	0/182 (Note 3)	8/27
Offshore Future CO_2 Booster Pumps Recycle Cooler	281.5	-46/50	182/144 5/7 (Note 1)	35/24 19/26 (Note 1)
Export Riser	256 (Notes 2 and 3)	-46/50	182	4/21

Notes:
1. Operating conditions of the offshore future CO_2 booster pumps recycle cooler are provided for the shell inlet/outlet and plate inlet/outlet respectively.
2. The riser is designed for the full shut in head of pumps regardless of the HIPPS employed. The pressure break on the pipeline to 1500# (Maximum Allowable Operating Pressure (MAOP) of the pipeline is 182 barg) is expected to be outside of the platform safety zone to satisfy the HSE requirements.
3. The export riser and pipeline is designed in line with PD 8010-2:2004. Pipeline design pressure (MAOP = 256 barg) is the pressure at which calculations are based on for the pipeline. The maximum incidental pressure is 10% above this value; 281.5 barg.
4. PIG launchers are covered under PD 8010-2:2004. However, parts of the launcher (end closures) would be designed to PD 5500:2012. The whole launcher is designed under PD 5500:2012 (for testing purposes) with a design pressure set at the maximum incidental pressure of the offshore pipeline of 281.5 barg.

4.4.6.2 Produced Water

Water production from the aquifer would not be required for the first load CO_2 injection rates, but once CO_2 injection rates increase after first load, water production would be required to maintain acceptable reservoir pressure; up to eight water production wells would be installed in phases over the design life.

Water dispersion modelling has shown that discharge of water at the seabed is unlikely to be environmentally acceptable due to inadequate dispersion. Water must be discharged at the sea surface to allow adequate dispersion. This can be achieved either by having individual well head structures for each water producer or by piping subsea water producers back to the central platform. This decision was not required to be made during FEED; however the provision of spare water production risers on the platform hub would facilitate future tie back of water producers if this option were to be selected. The water production wells would naturally lift due to the raised aquifer pressure. No electric submersible pumps would be required to drive water from the aquifer. It is expected that any future water production wells would be controlled and powered via umbilical from the central platform.

Two 400mm water production well risers would be pre-fitted in the platform. The future design of the water production flow lines would include one ESDV in each incoming line. The risers would allow two daisy chain tie backs from water production wells to the hub platform.

Flow measurement would be provided to measure the quantity of water that is discharged overboard with a sample connection installed to allow analysis of the well stream prior to routing overboard. Remote monitoring of the well stream would allow operation of the production wells to be managed. The CO_2 content of the incoming stream would also be monitored to avoid corrosion issues and degradation of the topsides pipework.

Deck space would be allowed for two temporary 400mm future PIG receivers for dewatering subsea flow lines after hydrotesting and a future header joining the two water lines with the pre-fitted produced water discharge caisson. The caisson would be sized to accommodate the following:

- flow from two future daisy chains with 662m^3/h of produced water each (1324m^3/h combined); and
- Seawater return from the future CO_2 booster pumps recycle cooler.

Marine growth within the caisson would be deterred using an anti-marine lining and a biofouling system.

Two spare J-tube are pre-fitted for control and power supply to future water production wells.

The design and operating conditions of the produced water facilities are as follows:

Table 4-14 Produced Water Facilities Design and Operating Conditions

Equipment	Design Conditions		Operating Conditions	
	Pressure (barg)	Temperature min/max (°C)	Pressure min/max (barg)	Temperature min/max (°C)
Import Risers	455.5 (Note 1)	-10/90	0/30	4/65
Produced Water Discharge Caisson	3.0		atm	4/65

Notes: 1. The future water production pipelines and risers are designed in line with PD 8010-2:2004. Pipeline design pressure (MAOP = 45.5 barg) is the pressure at which calculations are based on for the pipeline. The maximum incidental pressure is 10% above this value; 50 barg.

4.5 Support Systems

4.5.1 Power Generation

The main platform power sources would be from at least two or more independent, self-contained, air-cooled diesel generator sets, configured in a duty/auto-standby arrangement, running efficiently at platform base load, with provision for future demand anticipated during expansion phases of the reservoir development.

Redundancy would be on the basis of additional machines, rather than inefficient loading of oversized generators. The generators would be suitable to drive the seawater lift pump during water wash operations. The water wash injection pumps would be included as part of the water wash skid with self-contained diesel engine drivers. Large loads would be arranged to soft start in order to support this approach. A suitable design margin of at least 20% would be included.

Remote control, monitoring and fault diagnosis would be provided by serial link of generator Programmable Logic Controllers (PLCs) to the platform.

Each generator would have a safe local and remote operation instrumentation and control system for start-up, re-starting, synchronisation, running, shutdown, control and monitoring of the individual packages complete with all necessary alarm and safety shutdown systems. The entire start-up and shutdown sequence would be automatic.

Both generator control systems would communicate with the platform Integrated Control and Safety System (ICSS) through dual redundant serial interfaces allowing unattended operational monitoring and remote control from the onshore operator workstation.

A separate smaller emergency diesel generator package would be considered to provide power to statutory and safety systems.

The main and emergency power systems would operate at the European standard voltage of 400 V and 50 Hz. The generators would supply distribution switchgear located in a Local Equipment Room (LER). Selected outgoing circuits and supplies from the switchgear would be interfaced with the ICSS to allow remote monitoring and control from the onshore operator workstation.

Diesel fuel capacity and bunkering provisions would be consistent with the platform autonomy requirement. Diesel storage capacity would be sufficient for at least 100 days and be sufficient to supply the seawater lift pump and temporary water wash facilities injection pumps during water wash operations. Fuel supply should, if possible, be arranged to gravity feed to the machines such that diesel circulation pumps can be avoided.

4.5.2 Control and Automation Philosophy

It is proposed that the offshore platform is operated remotely from an onshore control centre as after start-up and commissioning, it is likely that only water wash would require manual intervention. All valves would be hydraulically or electrically operated.

The pipeline pressure would be controlled from the platform using the topsides pipeline backpressure control valve.

The platform would be designed for unmanned operation under remote supervisory control; systems would operate and control autonomously from the land based system at the control centre. Communications between the platform and the NGC control centre would be by means of dual redundant VSAT satellite links.

4.5.2.1 Hydraulic Control Packages

A hydraulic control package would provide hydraulic fluid at required pressure levels for the operation of topsides valves. The system would be configured with two 100% duty pumps in a duty auto/standby arrangement and it would have sufficient capacity in pressure accumulators to stroke all platform valves during a well start-up (including riser valves) without undue risk of low hydraulic pressure trip.

Speed control valves may be fitted in hydraulic impulse lines to control the opening speed of large valves to ensure this. Appropriate space would be allocated for future remote subsea or dry tree CO_2 injection wells and water producers hydraulic control equipment.

The maximum number of wells for the reservoir would be expected to be as follows:

Table 4.15: Maximum Number of Wells

Location	Number of Wells
Platform CO_2 wells for first load	3
Future remote CO_2 wells	5
Future remote water producers	8
Total	16

Note: Three platform CO_2 injection wells are specified for the first load project on the basis of the specified flow rate flexibility required by the first load.

The hydraulic system for the platform would be capable of operating up to six platform wells.

A wellhead control panel would control the initial platform CO_2 injection wells with suitable future expansion provision for the six slots.

4.5.2.2 Communications

Data would be acquired and transmitted to the onshore control centre to enable an operator to monitor and control the reservoir and facilities for injection, integrity and information purposes. Communications would include:

- Very Small Aperture Terminal (VSAT) link with back up;
- email and internet access;
- multiplexer;
- marine, aeronautical and platform radio systems – Very High Frequency/Ultra High Frequency (VHF/UHF);
- telephone system;
- aeronautical GPS (Global Positioning System);
- man overboard system;
- meteorological system; and
- Public Address/General Alarm (PA/GA) system.

4.5.3 Material and Fluid Handling

A diesel driven crane suitable for loading and unloading supply boats would be required; the crane would be suitable for handling:

- Water Wash equipment;
- PIG operations;
- wireline intervention equipment;
- chemical tote tanks; and
- nitrogen quads.

Fluid storage would be provided for diesel and fresh water for the emergency accommodation.

Lifting equipment would be required in the vicinity of the filters to enable filter cartridge removal.

4.5.4 Accommodation and Temporary Refuge

Emergency overnight accommodation would be provided for up to twelve people. It would also function as a temporary refuge providing a place for relief from weather, worksite meetings, first aid and meal breaks.

An LER would also be provided with the following:

- control and safety systems;
- main switchboard;
- telecoms equipment;
- operator station/control desk;
- Uninterruptible Power Supply (UPS) and other supporting utilities;
- heating and ventilation for accommodation and equipment room;
- battery room; and
- storage space.

4.6 Safety Systems

Safety considerations would be an important factor influencing the design of the end-to-end CO_2 transportation and storage chain. The large volumes of dense phase CO_2 present hazards not previously considered for a network of pipelines in the UK.

Key issues for consideration are:

- CO_2 toxicity;
- CO_2 physical properties changing under process conditions; and
- CO_2 detection.

Safety considerations would be the most important factor influencing the design of the end-to-end CO_2 transportation and storage chain.

Carbon dioxide is not harmful at small concentrations; people breathe out CO_2, but large volumes of nearly pure (higher than 96%) CO_2 presents a hazard. Key issues for consideration are the toxicity of CO_2 and its physical properties as the fluid is subjected to changes in process conditions.

4.6.1 CO_2 Toxicity

The toxicity of CO_2 is a measure of the harm it can do to our bodies.

The individual workspace exposure level of 0.5% (5,000ppm) for long term exposure (8 hours weighted average) and 1.5% (15,000ppm) for short term exposure (15 minutes weighted average) are to be used for the target CO_2 concentration for all safety cases and design studies. Indefinite outdoor exposure levels are deemed to be 0.2% (2,000ppm) over the average working life of 100,000 hours.

4.6.2 CO_2 Physical Properties

In the event of an uncontrolled release of CO_2, the escaping fluid would rapidly expand from the dense phase to a gas. The temperature of the released CO_2 would decrease rapidly and because CO_2 sublimes (transitions directly from vapour to solid) at lower pressures (≤ 5.1bara), some CO_2 “snow” would form. As a result of this low temperature CO_2, the moisture in the surrounding air would condense and a thick fog would form.

CO_2 readily forms hydrates with water and these have the potential to choke or block flowing pipelines if sufficient free water is available. For this reason, the specification on water within the CO_2 product stream is stringent, set at 50ppmv.

Since the phase of CO_2 may be affected by atmospheric temperature fluctuations and solar gain, piping systems and equipment would be predominantly buried, unless it is impractical to do so.

4.6.3 Fire and CO_2 Leak Detection

The fire risks on the platform are small, as CO_2 is non-flammable, However, the fire and CO_2 gas protection philosophy for the platform would be guided by the outcomes of the formal safety assessment studies to ensure that the effects of all credible fire and gas release scenarios would be controlled to reduce the risk to maintenance and service personnel, asset, reserves and the environment to an As Low As Reasonably Practicable (ALARP) level.

The Fire and gas system would be interfaced with a general alarm system to allow general and abandon facility/platform alarms to be transmitted to personnel. It would respond, appropriate to the event, to initiate necessary shutdowns and audibly alarm any personnel on the platform and at the onshore control room.

The main risks are presented by:

- helicopter activities;
- diesel storage;
- diesel engines; and
- electrical fires.

The primary personnel risk is from CO_2 release. The risks are:

- asphyxiation;
- low temperatures; and

- poor visibility in CO_2 clouds.

4.6.3.1 CO_2 Leak Detection

A project gas leak detection and control philosophy has been developed which defines the design approach and minimum functional requirements for the fixed CO_2 detection and alarm system.

The fixed CO_2 detection systems would consider a combination of:

- acoustic leak detection which detects ultrasonic noise with up to 10m coverage radius;
- infrared point detection for areas where CO_2 gas accumulation or ingress may occur such as enclosures and the heating ventilation and air conditioning inlet at the temporary refuge; and
- open path detection for areas where CO_2 gas migration may occur.

The infrared point detectors and open path detectors would alarm at two pre-set levels as shown in the table below:

Table 4-16 Alarm Set Points

Detector Type	High (Alert) (Note 1)	High-High (Action) (Note 2)
Infrared Point Detector	0.5%	1.5%
Open Path Detectors (Note 3)	50,000ppm.metres	150,000ppm.metres

Notes: 1. Long term exposure limit averaged over 8 hours.
2. Short term exposure limit averaged over 15 minutes.
3. Based on a 10m path length.

The alarm system field devices would include sounders and beacons. On confirmed CO_2 gas detection, audible and visual alarms would be initiated. Operators in the remote T&S Control Centre have control over the alarm system.

CO_2 gas detectors would be located in all areas of the platform where CO_2 can accumulate. CO_2 is denser than air so confined low points and poorly ventilated areas would be avoided wherever possible. Portable CO_2 detectors would be carried by operations and maintenance personnel.

Manual alarm call points would be distributed throughout the platform.

The helideck would be provided with a dry powder unit and CO_2 extinguisher at each of the two main access points. The CO_2 extinguishers would be fitted with extended applicator horns for use with helicopter engine fires. Other portable and wheeled fire extinguishers would be placed at strategic locations around the platform.

4.6.3.2 Emergency Escape

The primary escape routes would be aboard a helicopter or a support vessel. Given that CO_2 is non-flammable and denser than air the use of the temporary refuge until a leak has been isolated and dispersed would also be considered. This would require a suitable air supply; breathing apparatus escape kits would be provided within the refuge and around the platform.

The platform would be fitted with life rafts and, depending on the results of safety studies, a lifeboat.

4.7 Venting Philosophy

Venting of CO_2 from the entire end-to-end transportation and storage system, in other words the complete depressurisation of the pipeline, would be a very rare event and would mainly be required for safety, reasons. Venting large volumes of high concentration (≥ 96 v/v%) high pressure CO_2 into the atmosphere has health, safety and environmental implications which impacts the engineering design.

Limited local venting would be required for the following objectives:

- commissioning;
- start-up;
- off specification CO_2;
- thermal relief;
- maintenance activities; and
- the continued operation of systems when certain sections of the full chain are shutdown.

Since CO_2 is heavier than air at atmospheric conditions, care would be required when locating vent stacks. The dispersion of the CO_2 would be carefully modelled to determine that normally or occasionally occupied building in the proximity of the discharge vent (usually a stack) would not be impacted by the CO_2 as it disperses.

4.7.1 Permanent and Temporary Vent Stacks

Both permanent and temporary vent stacks are proposed for use throughout the transportation and storage system located at the various above ground installations. Permanent vents would be located at:

- Drax OPP (sized for the full CO_2 mass flowrate),
- Barmston Pumping Facility (to allow maintenance of some items of equipment), and
- the offshore NUI.

Onshore, stacks would discharge vertically upwards into a freely ventilated area; the end of the stack would be sized for local operating conditions, but would be probably at of the order of 8m above ground level. The visual impact of these structures would be a constraint on the height.

On the NUI, the common vent boom is located outboard of the cellar deck at platform north east. As for all the other vent lines, the pipeline vent line tip is angled at 45° downwards so that releases in unfavourable wind conditions are dispersed beneath cellar deck elevation.

At Barmston, the discharge lines from relief valves protecting major equipment items such as PIG receivers/launcher, CO_2 fine filters, CO_2 Booster Pumps Recycle Cooler would be routed vertically to atmosphere at a safe location point 3m above ground level. The discharge lines are sized in order to maintain a high velocity to aid dispersion, but within sonic velocity limits, so that the flow would not be choked. Permanent vent stacks would be required for:

- metering package;
- downstream filter vents; and
- CO_2 Booster Pump Discharge pipework.

Temporarily installed vent stacks may be required for:

- block valve installations (excluding depressurisation of pipeline section, see paragraph below);
- PIG launchers/receivers; and
- pressurising bridle arrangements (pipework spurs).

Where required for the depressurisation of a pipeline section via a Block Valve Station, the temporary vent stack would discharge vertically upwards, locally into a freely ventilated area with the end of the stack being 5m above ground level.

4.7.2 Depressurisation

Depressurisation of the onshore or offshore pipelines would only be performed in an emergency. The operational intent for the pipelines would be to keep the CO_2 content in the dense phase by means of maintaining the pressure above 90barg throughout their lifetime.

4.7.3 Noise

The noise generated at the vent tip as a result of CO_2 venting operations will require consideration of the occupational health limits.

4.7.4 Dispersion

An Environmental Impact Assessment (EIA) study would be required for permanent vents and should include CO_2 dispersion modelling, which takes into consideration wind direction, wind strength, the topography of the location and the vent height and orientation.

The venting system would be designed to maximise air mixing at the tip and to ensure that effective vent velocities are maintained in order to promote effective dispersion of CO_2 into the atmosphere.

4.7.5 Low Temperature

The cooling effects of depressurisation need to be taken into account when designing the vent systems for a CO_2 transportation system. In cases where very low temperatures are predicted, venting procedures would need to be developed to mitigate these effect, for example, controlling the time period for venting, thereby pausing the procedure and allowing it to warm up for a period of time before continuing venting.

The venting systems would also be designed to minimise the likelihood of personnel coming into contact with the released CO_2 as this could result in cold burns.

Consideration would be given to the design and location of the vents as a means of mitigating the effects of the resultant low temperatures; for example, venting from the bottom of a pipe reduces the cooling affect as liquid CO_2 has a lesser Joule-Thomson effect (cooling upon expansion) than gaseous CO_2.

4.8 Effluent & Emissions Discharge Summary

From the process, there are no continuous effluent or emission streams. Occasionally, the process requires depressurisation for maintenance and therefore inventories shall be vented, and in process-upset conditions, thermal relief valves shall release inventories.

The worst-case scenario, pipeline depressurisation, has also been considered. From the utilities, the diesel generator exhaust is the only continuous source of emission and is the largest direct source of emissions for the whole project.

4.8.1 Installation And Commissioning

Emissions from support vessels and other equipment required for the installation and commissioning phases shall not be included in this Discharge Summary. These emissions are being quantified by the EPC contractor when such information is available. However, typical sources during these phases have been identified below:

4.8.2 Air Emissions

Typical emissions to air would come from the following sources:

- Transportation exhaust from helicopters and vessels transporting materials, equipment and personnel;
- Construction exhausts from installation equipment (e.g. crane and winch motors);
- Exhausts from diesel generators used to provide power for the platform during start-up and commissioning; and
- Other emissions to air during commissioning from venting during start-up.

The summation of the CO_2 emissions across the scenarios is provided below. The largest contributor to the total air emissions comes from complete pipeline depressurisation, and an estimated frequency of once every 20 years is a conservative estimate.

Table 4.17: Air Emissions Summary

Location	Normal Operation Average CO_2 Emissions per year (t/year)	Abnormal Operation Average CO_2 Emissions per year (t/year)
PIG Operatons	5.31	-
CO_2 Filters	10.46	-
Topsides	10.91	-
Wellhead	2.84	-
Diesel Generators	393.60	-
Thermal Relief Valves	-	5.74
Offshore Pipeline	-	1192.08
TOTAL	423.12	1197.83

4.8.3 Liquid Effluents

Liquid effluents during operation would come from the following sources:

- Sewage from the installation and commissioning personnel;
- General liquid wastes including diesel, oil, lubricants, solvents etc. (hazardous and non-hazardous);
- Discharge of hydro-test water;
- Dewatering of pipelines prior to start-up.
- Domestic wastewater and sewage;
- Deck runoff drains; and
- General oils, lubricants, chemicals, and solvents.

As the Platform is an NUI so domestic waste and sewage are minimal and can be discharged directly into the sea with the outlet pipe located 2m below sea level underneath the cellar deck. The domestic wastewater rate has been assumed the same as the fresh water usage.

Other non-hazardous and hazardous liquid waste shall be removed by swabbing and disposed as per the Waste Management Plan (WMP). However, two systems have a drain connection; the diesel system and the MEG system, both drains flow to a tote tank to be shipped onshore for disposal in accordance with the WMP.

Table 4.18: Liquid Effluent Summary

Emission Source	Mass (kg/person/day)	Freq. (day/year)	POB	Mass per year (t/year)
Domestic Waste Water	300	16	12	57.6

For liquids, the unmanned nature of the Project reduces the volume of discharges greatly, as well as removing the need for the infrastructure required to permanently support personnel (potable water system, sewage treatment system).

Solid waste is generated when personnel are present and this domestic waste shall be taken onshore and recycled or taken to domestic landfill. Hazardous waste (i.e. oily rags, soaked media) shall be taken to a Waste Management Contractor.

5 Summary

CO_2 would be routed through a 600mm subsea pipeline from the landfall on Barmston beach to an offshore wellhead injection platform located at the reservoir.

The subsea pipeline and offshore platform would have a forty year design life for fatigue and corrosion. Facilities subject to obsolescence, such as control systems, which may have a shorter design life and require upgrade or replacement, would be identified.

The infrastructure design approach and configuration would be described by considering:

- the subsea pipeline and its:
  - mechanical integrity including the design criteria, strength, stability, span lengths, criteria for pipeline and cable crossings and leak detection;
  - connections for risers, tie in spools, PIG operations and flanges with consideration given to the next phase when platform layout and orientation was confirmed;
  - protection, along with the possible causes of damage and their mitigation;
  - materials and coatings for line pipe, components, PIG traps and closures;
  - corrosion management; and
  - construction of the pipeline;
- the offshore platform and the:
  - configuration including future expansion with a description of the facilities; and
  - fabrication of topsides, the substructure and the future module with the materials used;
- the processes, which take place on topsides, and at the reservoir covering:
  - a description of the flow rates and optimum composition of $CO_{2;}$
  - import riser;
  - PIG receiving facilities;
  - CO_2 filters;
  - CO_2 injection wells and import valves;
  - utilities on the platform including water wash treatment, seawater lift pumps, hydrate inhibition and CO_2 vent and drains; and
  - future processes anticipated: CO_2 export from the platform and water production to maintain acceptable reservoir pressure; and
- support systems on the platform:
  - power generation using diesel generator sets;
  - control and automation packages;
  - material and fluid handling;
  - accommodation and temporary refuge; and
  - safety systems including emergency escape, fire and CO_2 detection.

6 Glossary

Abbreviations	Meaning
3D	3 x Diameter
5D	5 x Diameter
ALARP	As Low As Reasonably Practicable
Ar	Argon
atm	Atmospheric pressure
°C	Celsius (temperature measure)
CCS	Carbon Capture and Storage
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPL	Capture Power Limited
CWC	Concrete Weight Coating (for offshore pipelines)
DECC	UK Government's Department of Energy and Climate Change
DIFFS	Deck Integrated Fire Fighting System
EOR	Enhanced Oil Recovery
ESDV	Emergency Shut Down Valve
FEED	Front End Engineering Design
FBE	Fusion Bonded Epoxy
GPS	Global Positioning System
H_2S	Hydrogen sulphide
H_2	Hydrogen
H_2O	Water
HDD	Horizontal Direct Drilling
HIPPS	High Integrity Pressure Protection System
HVDC	High Voltage Direct Current
HYSYS	Oil and gas process simulation software that enables optimization of conceptual design and operations
ICSS	Integrated Control and Safety System
in	inch
IID	Internal inspection device (intelligent PIG)
KSC	Key Sub-Contract
LER	Local Equipment Room
MAOP	Maximum Allowable Operating Pressure
MEG	Mono Ethylene Glycol
MIP	Maximum Incidental Pressure
MSF	Module Support Frame
MTPA	Million Tons Per Annum
N_2	Nitrogen
NaCl	Salt
NO_x	Generic term for the mono-nitrogen oxides, and nitric oxide (NO) and nitrogen dioxide (NO_2)
NGCL	National Grid Carbon Limited
O_2	Oxygen

PA/GA	Public Address/General Alarm
PIG	Pipeline Inspection Gauge
PREN	Pitting Resistance Equivalent Number (corrosion resistance measure of a material)
PTFE	PolyTetraFluoroEthylene
SACS	structural design & analysis software
SAWL	Longitudinal Submerged Arc Welding
SO_x	Generic term for the Sulphur Oxides the two major ones being sulphur dioxide (SO_2) and sulphur trioxide (SO_3)
SOL	Safe Operating Limit
SSIV	Sub-Surface Isolation Valve
TEMPSC	Totally Enclosed Motor Propelled Survival Craft
T&S	Transport and Storage
UPS	Uninterruptible Power Supply
VAP	Virtual Anchor Points
VHF/UHF	Very High Frequency/Ultra High Frequency
VSAT	Very Small Aperture Terminal
WMP	Waste Management Plan
w/w	Weight/Weight

Term	Explanation
Austenitic stainless steels	Alloys containing chromium and nickel, and sometimes molybdenum and nitrogen
Biocide	A chemical substance or microorganism which can deter, render harmless, or exert a controlling effect on any harmful organism by chemical or biological means
Biofouling	Also known as biological fouling, is the accumulation of microorganisms, plants, algae, or animals on wetted surfaces
Blowdown	A type of venting which releases natural gas from a pipeline to atmosphere
Caisson	A watertight structure for underwater work, consisting of an airtight chamber, open at the bottom and containing air under sufficient pressure to exclude the water
Carbon capture	Collection of carbon dioxide (CO_2) from power station combustion process or other facilities and its process ready for transportation
Co-fire biomass	Co-firing is the combustion of two different types of materials at the same time. One of the advantages of co-firing is that an existing plant can be used to burn a new fuel, which may be cheaper or more environmentally friendly. In this case, biomass can be co-fired in existing coal plants instead of new biomass plants
Daisy chain tie backs	An arrangement where a new subsea tie back is linked to an existing tie back, using excess flow line capacity to reach the platform
Dense Phase	The physical properties of CO_2 can vary according to temperature and pressure. It can be a gas, solid, liquid or can exist in a 'supercritical' state, where it behaves as a gas but has the viscosity of a liquid. The term 'dense phase' refers to CO_2 in either the supercritical or liquid stage
Dewatering	Removal of water from the pipeline after the hydrotest prior to start-up
Dogger Bank Creyke Beck	Forewind offshore wind turbine array areas planned in the Dogger Bank Zone
Dry tree	Often called a production tree or Christmas tree. Wellhead device installed at the surface of the well, including casing heads and a tubing head combined to provide surface control of the subsurface conditions of the well.
FEED contract	CPL have entered into an agreement with the UK Government's DECC pursuant to which it would carry out, among other things, the engineering, cost estimation and risk assessment

	required to specify the budget required to develop and operate the White Rose assets
First load	The amount of CO_2 produced during the first year of the CO_2 transportation system
Full chain	The complete process from the capture of the CO_2 at the emitter plant to its injection into the storage reservoir
Halite	Rock salt
Hang off module	An extension to the existing platform to house equipment; designed to be substantially constructed onshore then shipped out and hung off the existing structure
Hydrate inhibition	Chemical prevention of hydrate formation, in this project MEG is used to compete with the hydrate structure for water molecules
Hydrotest	Process by which the pipeline is pressure tested to a predefined pressure above the operating design pressure of the pipeline
Injection manifold	A subsea structure containing a network of valves and pipework designed to direct injection fluids to one or more subsea wells
Injection well	Deep subsurface rock formations identified for long-term storage
Inventory	An accounting of the amount of gas discharged into the atmosphere. An inventory usually contains the emission of one or more specific greenhouse gases or air pollutants within a specified time span in a specified place
Jacket	A welded tubular steel frame with tubular chord legs supporting the deck and the topsides in a fixed offshore platform
Key Knowledge Deliverable	A series of reports Including this one) issued as public information to describe the flows and processes associated with the overall system. Also referred to as a KKD
Nitrogen quads	Manifold pack holding nitrogen cylinders connected to one outlet
NUI	Normally unmanned installation
Oxy-fuel	A power plant technology which burns fuel in a modified combustion environment with the resulting combustion gases being high in CO_2 concentration which allows the CO_2 produced to be captured without the need for additional chemical separation
Oxygen scavenger	Also known as oxygen absorbers, these are added to enclosed packaging to help remove or decrease the level of oxygen in the package. They are used to help maintain product safety and extend shelf life.
PIG operations	An essential maintenance activity that optimises the smooth operation of the pipeline using a Pipeline Inspection Gauge (PIG) to traverses the pipeline to inspect and clean it.
PIG launcher/receiver	The PIG enters the line through a PIG trap, which includes a launcher and receiver and is driven by the process gas, to provide an essential maintenance activity that optimises the smooth operation of the pipeline.
Phase envelope	The behaviour of a gas at different phases represented as a function of pressure and temperature.
Piles	Also called leg piles. Thick lengths of steel inserted in the tubular chord legs of the jacket and penetrate the sea floor up to 100 meters deep to ensure the stability of the whole platform and fix the jacket onto the seabed.
PLC	Programmable Logic Controller
Re-drills	A drilling operation to recomplete the well in the same or different geologic zone
Reservoir	Containment in suitable pervious rock formations located under impervious rock formations usually under the sea bed
Skirt piles	Piles inserted through and connected to sleeves at the base of the structure to anchor it
Smart Wind	Hornsea offshore wind farm
Subsurface modelling	The applied science of creating computerised representations of portions of the Earth's crust based on geophysical and geological observations made on and below the surface
Tie backs	A connection between a new subsea well discovery and an existing subsea well facility
Tie in	A connection between an existing and new pipeline. During pipeline construction 'tie-in' points are left at regular intervals and at crossings

Triple point	the temperature and pressure of a substance at which the three phases (gas, liquid, and solid) of that substance coexist in thermodynamic equilibrium
Topsides	The upper half of the offshore platform structure, above the sea level, outside the splash zone, on which equipment is installed
Transport	Removing processed CO_2 by pipeline from the capture and process unit to storage
Well bore	The hole that forms the well
White Rose Transport and Storage FEED Project	CPL and NGCL have entered into a key sub-contract agreement where NGCL would perform this project which would meet that part of CPL's obligations under the FEED Contract which are associated with the transport and storage assets
w/w	Weight/Weight. In a solution, it infers the percentage of substances by weight. For example, a Hydrochloric Acid 28% w/w solution means there are 280 grams of Hydrochloric Acid for every Kilogram of the solution (the remainder being water)