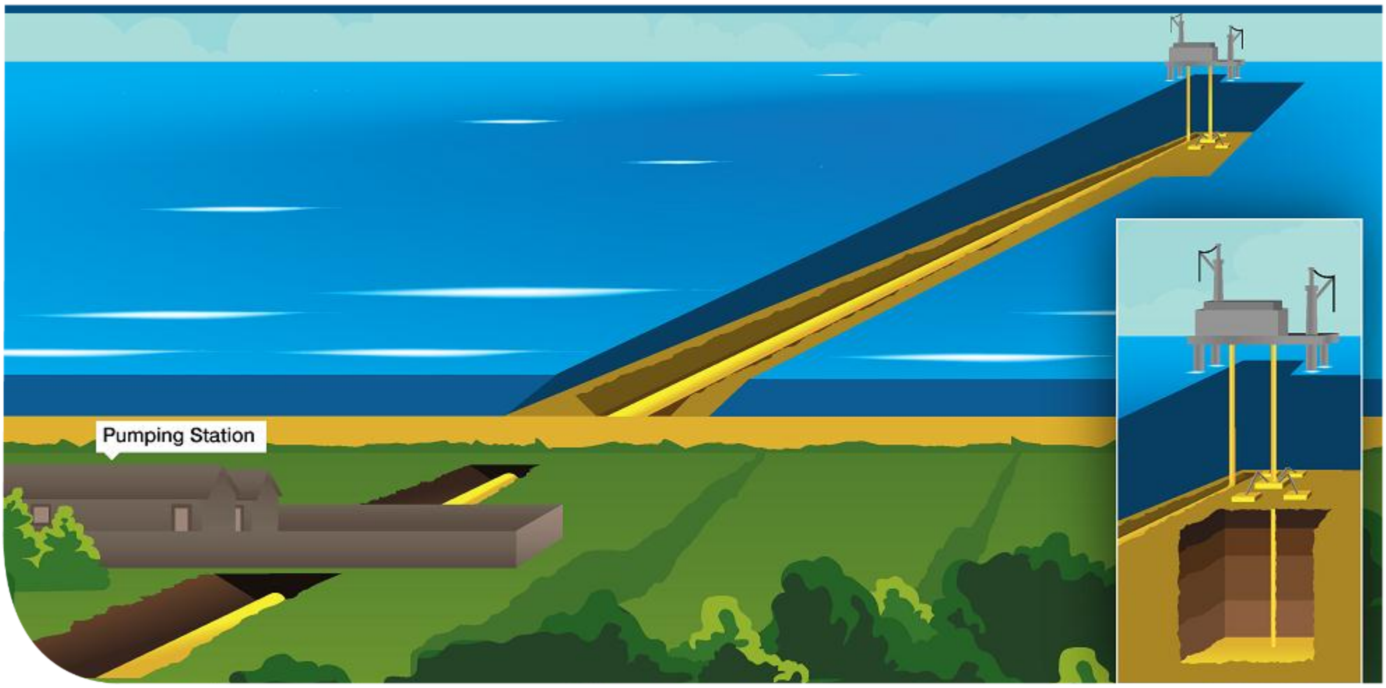
December 2015

K39: Subsurface Production Technology Report

Transport and Storage



IMPORTANT INFORMATION

Contents

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.
Flowline Well Interaction	A control description of the main CO_2 process flow scheme at the offshore storage facility from the riser up to and including the wellhead
Formation Temperature	Data from appraisal wells is used to estimate the temperature gradient within the Endurance Bunter Sandstone Formation
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
Injectivity and Thermal Fracture Analysis	Software modelling is used to design and evaluate the potential for fracturing in the Bunter Sandstone Formation and its impact on inflow performance
Key Knowledge	Information that may be useful if not vital to understanding how some enterprise may be successfully undertaken
Pressure Prediction	Knowledge of formation pressure was used to anticipate potential bore hole stability problems and to design suitable mitigation measures
Storage	Containment in suitable pervious rock formations located under impervious rock formations usually under the sea bed

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 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 Storage (CCS), which would generate up to 448MWe (gross) while capturing at least 90% of the carbon dioxide (CO_2) emissions. CCS technology allows the carbon dioxide produced during combustion to be captured, processed and compressed before being transported to storage in dense phase. The dense phase carbon dioxide would 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 report describes the analysis of the interaction between reservoir, well and flowline to optimise inflow and outflow performance of the White Rose Storage system whilst operating within design parameters. It includes a description of (formation) temperature and pressure prediction, injectivity analysis, injection fracturing analysis, operations support, and flowline well interaction.

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 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 KSC) pursuant to which NGCL will perform a 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.

This document describes the analysis of the interaction between reservoir, well and flowline to optimise inflow and outflow performance of the White Rose Storage system whilst operating within design parameters. It includes a description of (Formation) Temperature and Pressure prediction, Injectivity analysis, Injection fracturing analysis, Operations support, and Flowline well interaction.

2 Purpose

The purpose of this document is to provide a summary description of the subsurface production technology and includes:

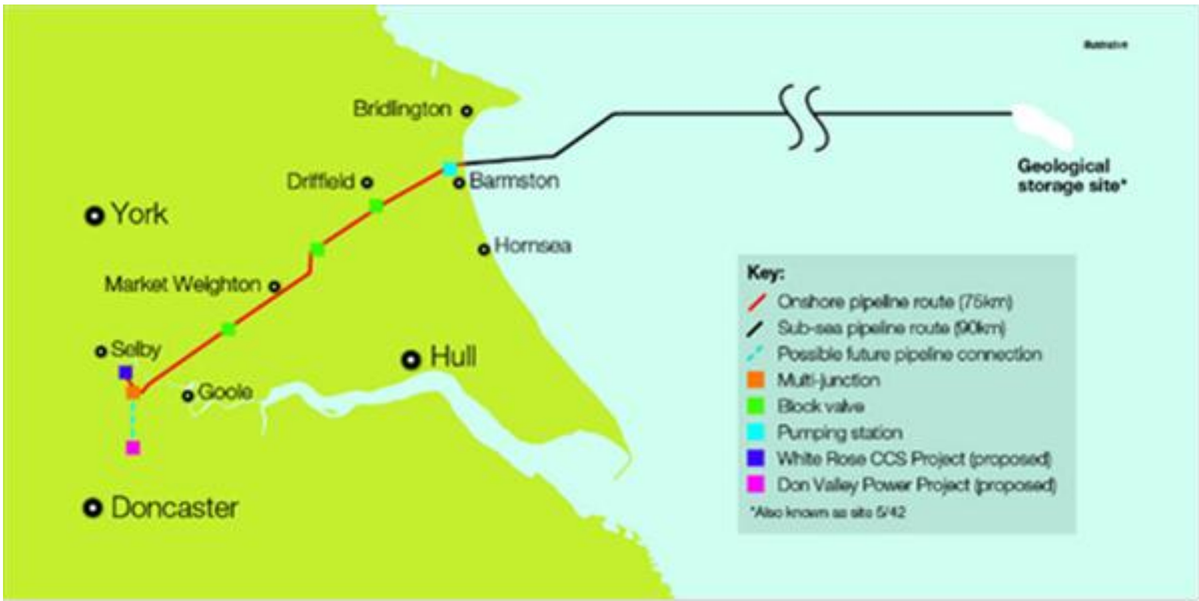
- temperature and pressure prediction;
- injectivity analysis;
- injection fracturing analysis;
- operational support; and
- flowline well interaction.

3 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 that is equipped with full 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

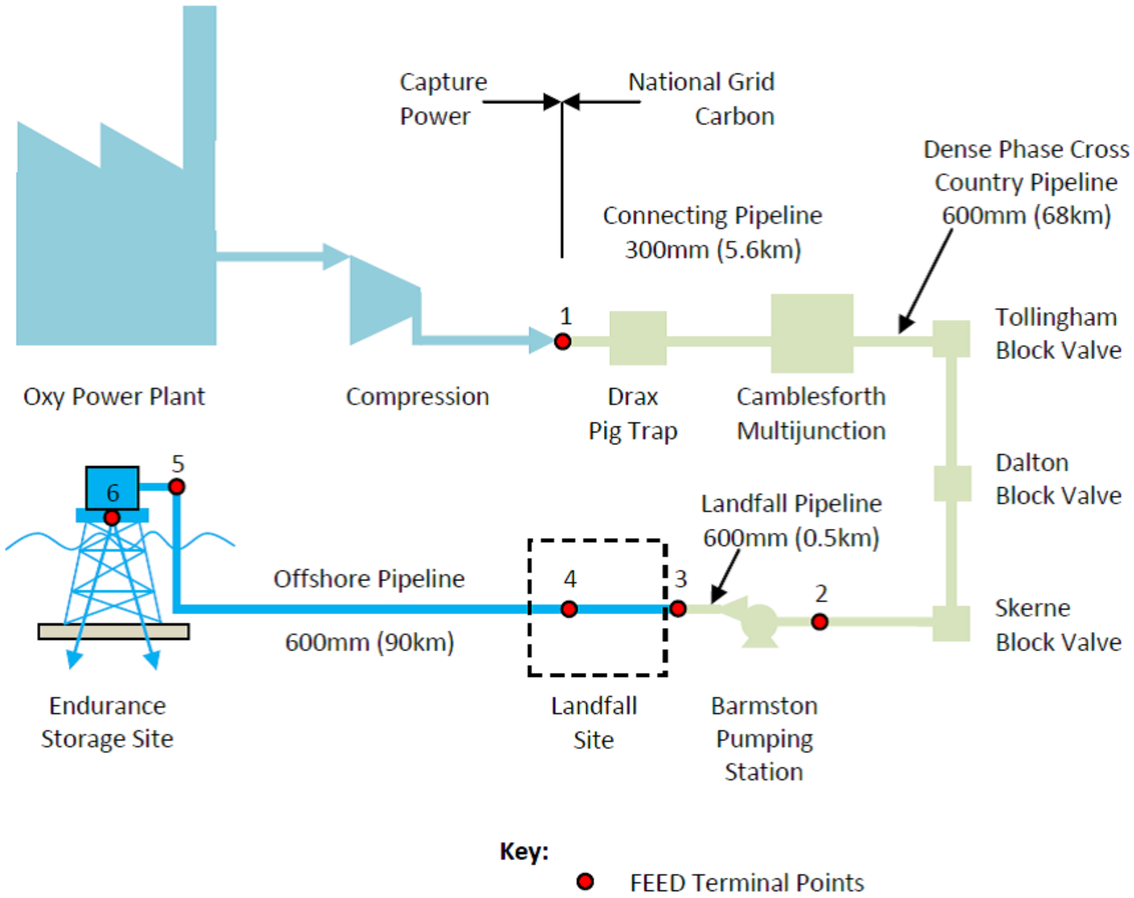


The standalone power plant would be located at the existing Drax Power Station site near Selby, North Yorkshire, generating electricity for export to the Electricity Transmission Network (the “Grid”) as well as capturing approximately 2 million tonnes of CO_2 per year, some 90% of all CO_2 emissions 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 reservoir) for permanent storage.

The power plant technology, which is known as Oxyfuel 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 structure of interest (identified as Endurance; formally as 5/42) is a four-way dip-closure straddling quadrants 42 and 43. This structure is a saline aquifer, approximately 22km long, 7km wide and over 200m thick. The crest of the reservoir is located at a depth of approximately 1020m below the sea bed. Reservoir datum (at 1300m TVDSS) pressure and temperature were determined as 140.0bar and 55.9°C, respectively. A layer of mudstone called the Rot Clay provides the primary cap rock or seal. This in turn is overlain by more than 90m of a salt layer known as the Rot Halite which is anticipated to provide additional seal capability.

4 The Offshore Storage Facility

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

Dense phase CO_2 is pumped, from the Barmston onshore facility, through a 600mm ND (24in) subsea pipeline and up through a 600mm ND (24in) riser arriving at the offshore storage facility platform topsides.

On the platform the CO_2 is filtered and routed to the injection wellheads. The wellhead and tree is the component at the surface of a well that provides the structural and pressure-containing interface for the equipment. The choke valves, located upstream on the tree, control the flow of the injected CO_2 and maintain sufficient back-pressure on the upstream system to ensure that the CO_2 remains in the dense phase.

The CO_2 is injected into a saline aquifer storage site located in block Endurance of the southern North Sea. Three moderately deviated (< 60^o) injection wells are planned initially with space available for a further three. Note that a moderately deviated injection well is one which is subject to a conventional well drilling operation where the drill bit is deflected at an angle from the vertical toward a specific target.

4.1 The Offshore Platform

The platform consists of the following facilities:

- PIG receiving facilities;
- cartridge type fines filters;
- CO_2 injection manifold;
- three individually metered CO_2 injection wells;
- utilities:
  - Monoethylene Glycol (MEG) storage and pumps to prevent CO_2 hydrate formation during well start-up operations;
  - seawater lift pumps and filters; primarily to supply seawater to the temporary wash water package;
  - temporary wash water package skid containing injection pumps, filters, power generation and chemicals. These are required for periodic well washing to avoid halite (rock salt) build up in the near wellbore region when CO_2 injection is shut-in;
  - corrosion inhibitor injection system for downhole protection of wetted well section; and
  - other utilities (drains system, diesel storage system, nitrogen system (quads), fresh water tank system, power generation system, CO_2 vent, wellhead hydraulic power unit);
- support systems (crane, temporary safe refuge, battery room, marine navigation aids and helideck);
- safety systems (fire and CO_2 gas detection systems, life rafts, Totally Enclosed Motor Propelled Survival Craft (TEMPSC) and helideck foam and Deck Integrated Fire Fighting System (DIFFS) package);
- Integrated Control and Safety System (ICSS) and telecoms systems, including a Very Small Aperture Terminal (VSAT) system; and
- water disposal caisson to allow disposal of produced water from the injection aquifer (future requirement) and seawater cooling return line.

The platform substructure will be a steel jacket (a welded tubular steel frame with tubular chord legs supporting the deck and the topsides in a fixed offshore platform with additional allowance built in to allow for future installation of CO_2 booster pumps to transport CO_2 further afield). Spare risers and J-tubes; conduits attached to the platform, will also be provided.

4.2 CO_2 Injection Wells

The design of the CO_2 injection wells takes into account the following main considerations, in addition to requirements of the wells basis of design:

1. the thermodynamic characteristics and physical properties of the specific composition of the CO_2 to be injected;
2. the robustness, reliability and safety of the well design for injection of CO_2 and for its isolation and repair in the event of failure during the injection phase;
3. the ability to reliably, permanently and safely seal the wells for the secure storage of CO_2; and
4. three wells are required to provide the reliability and to meet the system availability criteria of the transport and storage system.

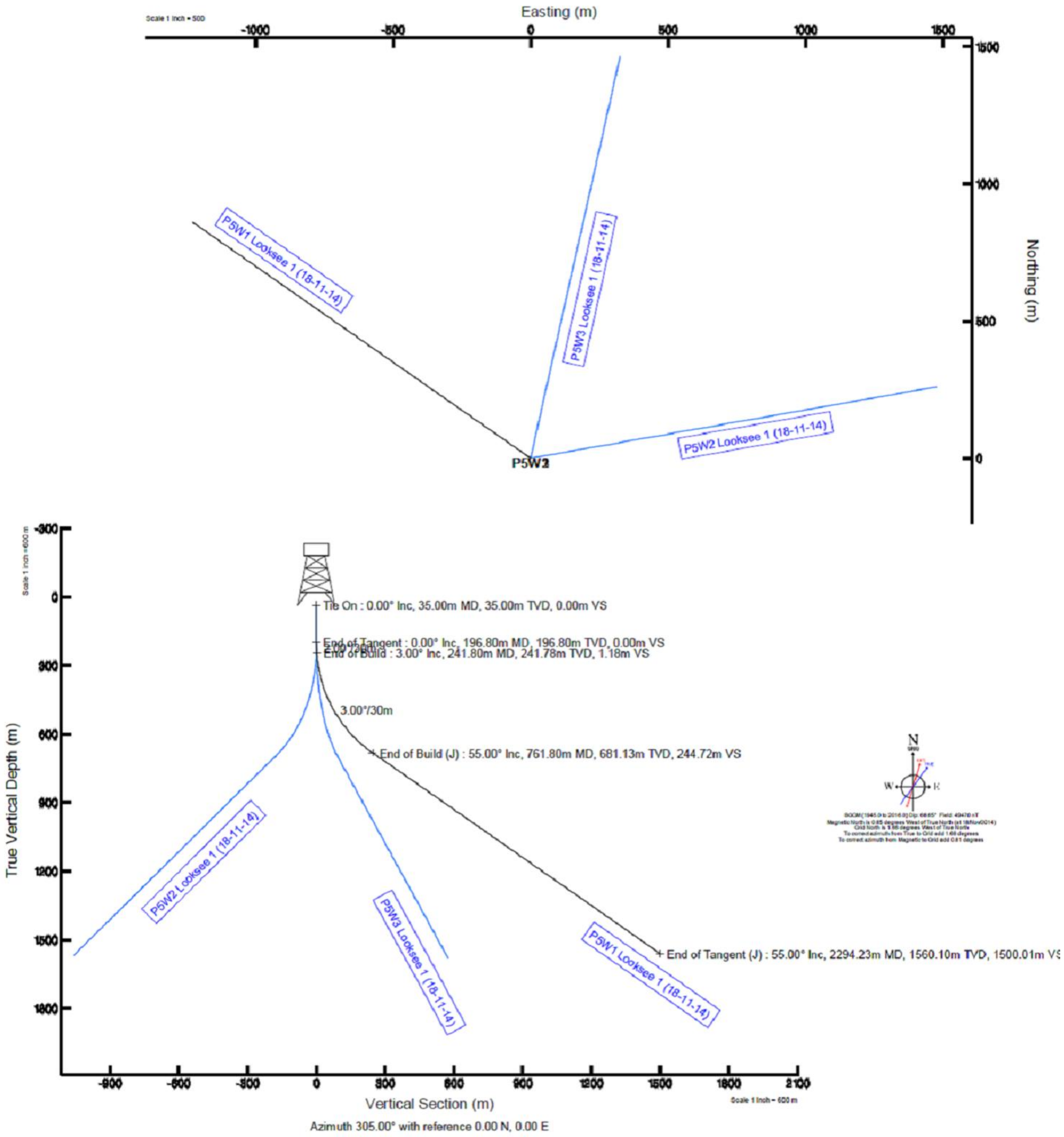
The main drivers for the moderate deviation (~55°) well design are:

- to optimise the reservoir placement and particularly to maximise the separation between the injection points;
- to ensure that the wells are accessible for wireline intervention where electric cables are used to transmit data about the well; and
- to limit wellbore instability issues drilling.

The injection wells are designated P5W1; P5W2 and P5W3, named for the choice of the fifth platform location and the drilling sequence number. The designations are often shortened to W1; W2 and W3.

On Figure 4.1 the co-ordinates are the target locations, the depths are based upon the penetration at the top of Bunter Sandstone and the positional tolerance for each well is a 100m x 150m rectangle oriented with the long side east to west.

Figure 4.1: Three injection wells in Plan and Section



4.2.1 Completion Design

The objective of the injection wells is to facilitate safe, reliable, and efficient construction, and subsequent use of the storage site for the injection of CO_2 for a period of 20 years. The wells are expected to cater for a range of injection rates; from a minimum equivalent to 0.58MTPA to a maximum equivalent to 2.68MTPA.

Flow assurance studies indicate that the range of pressures and temperatures downstream of the choke will under certain conditions and for relatively short duration will result in the presence of a two phase region in the upper completion. Two phase flow will occur during certain start-up conditions, but will not pose any risk to the mechanical integrity of the wellbore for either 4.5in or 5.5in tubing strings.

The mechanical configuration of the wells is the same as those typically used in oil and gas production wells which can withstand continuous three phase flow, including handling of substantial fluid slugs and consequently any oscillation/vibration due to short-term two-phase flow is not a cause for concern for the CO_2 injections wells. The design of the wells will consider:

- the short-term CO_2 injection ; and
- the permanent store integrity with the need to monitor and verify this integrity in the post closure phase.

A perforated injection liner will be cemented in place against the sand face of the wellbore. Figure 4.2 shows a schematic of a generic completion design for the CO_2 injection wells, where downhole, the sand face of the well is completed with a 7in cemented and perforated liner.

A completion is a conduit for injection between the surface facilities and the aquifer. A 5½in upper completion will be run comprising the following equipment:

- permanent packer; note that this is a device that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the wellbore. It is constructed of materials that are easy to mill out;
- seal mandrel; note that this is a device which allows access to the well without removing the packer;
- permanent downhole pressure;
- temperature gauge system;
- completion tubing; and
- tubing retrievable safety valve.

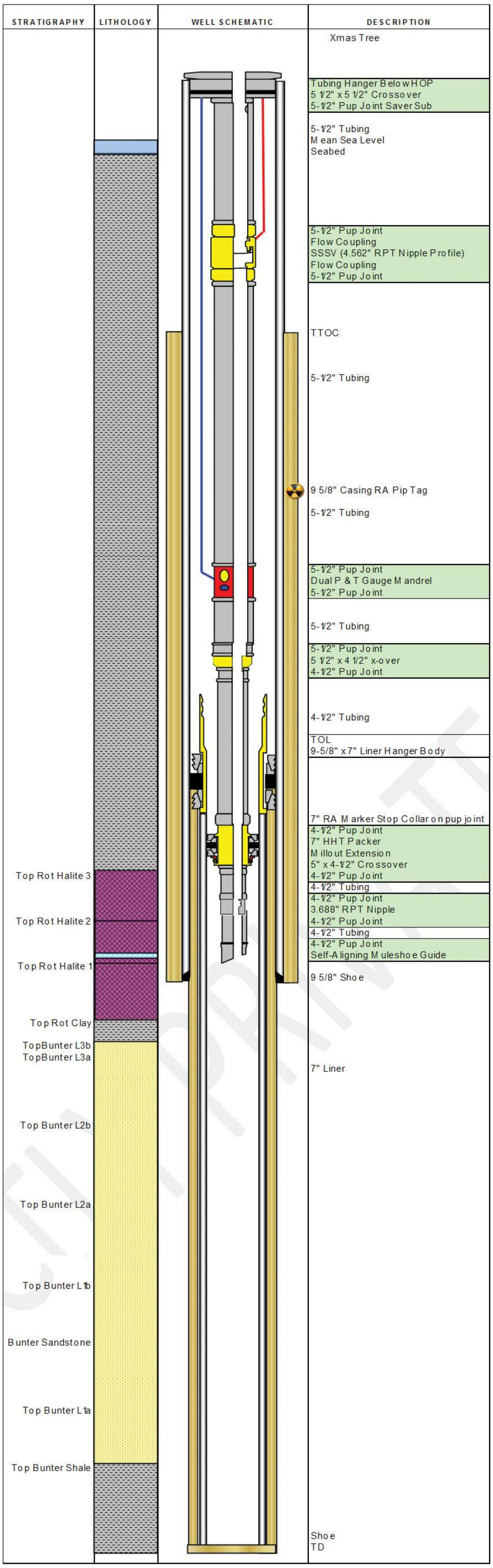
Perforations will be in the lower (deeper) 50% of the Bunter Sandstone layer. The well and completion design including material selection will be adequate for the expected minimum potential temperature of -20°C to -30°C associated with Joule-Thomson cooling due to the surface CO_2 injection choke. Note that Joule-Thomson cooling is when a real gas expands from high to low pressure at constant enthalpy (thermodynamic potential).

The completion and casing will be tested to a maximum of 5000psi (345bar). This is in excess of both the anticipated final reservoir pressure (circa 200bar) and the pipeline design pressure of 200bar. The pressure testing requirement is due to the maximum expected pressures associated with well operations including tasks such as packer setting or perforating and are currently anticipated to be up to 4500psi (310bar).

The design will allow for treatment of potential corrosion due to the periodic water wash treatments that may be required to treat halite deposits. Halite deposits may occur in the near wellbore region of the storage reservoir due to drying-out caused by the injected CO_2.

Hydrate management, which may be required during well start-up after a long duration shut-in or after a water wash treatment, will be by the use of MEG.

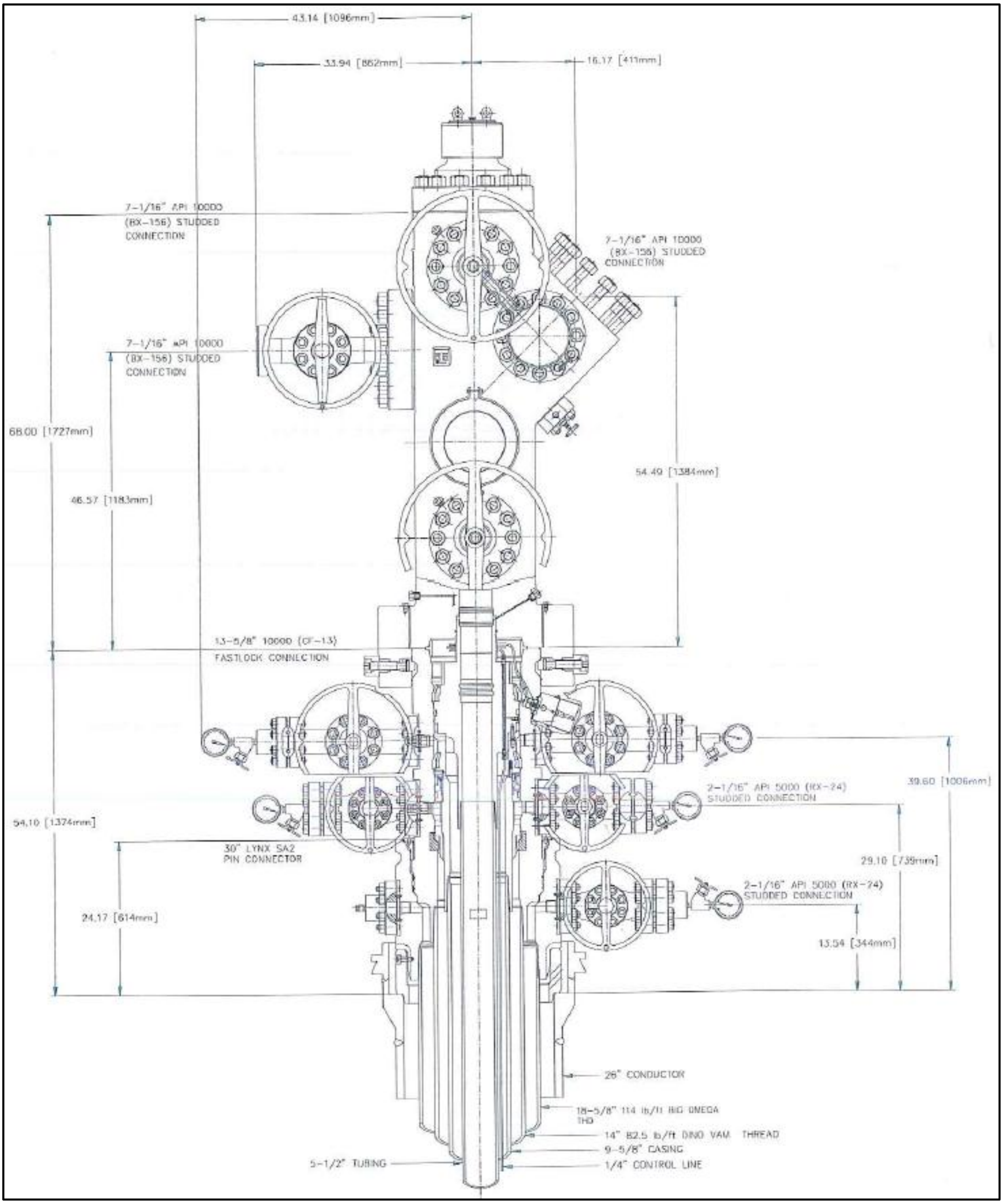
Figure 4.2: Generic Well Completion Design Schematic for CO_2 Injection Wells



4.2.2 Wellhead

A standard design compact wellhead rated for 5,000 psi maximum working pressure in slim-hole configuration will be used for the injection wells; see the schematic shown in Figure 4.3.

Figure 4.3: Typical Compact Wellhead and Injection Tree



4.2.3 Christmas Tree

A christmas tree, often called a production tree or dry tree, is a wellhead device installed at the surface of the well to provide surface control of the subsurface conditions of the well.

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

The 5⅛ inch bore is compatible with 5½in tubing. The tubing hanger and wellhead will have ports to accommodate between four and six downhole feed-throughs for hydraulic, electrical or fibre-optic functions with redundant ports blanked. 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 corrosion resistant alloys 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 Pitting Resistance Equivalent Numbers (PREN) greater than 40.

Note that PREN (or PRE) numbers are a theoretical way of comparing the pitting corrosion resistance of various types of stainless steels, based on their chemical compositions; they are useful for ranking and comparing the different grades.

5 Formation Temperature and Pressure Prediction

5.1 Temperature

A number of temperature measurements were made in the 42/25d-3 appraisal well. The reliability of the measurement varies depending on the accuracy of the various tools and the time spent by the tools at the depth of interest during measurement. This latter point relates to the time required for the tool to heat (if moving down the hole) or cool (if moving up the hole) to the local temperature. The sets of measurements at which the tools were given most time at any given depth were those associated with:

- the Modular Dynamic Tester (MDT) measurements of pressure; the MDT long duration test (20 depths);
- Wireline Head Thermomete (WHT) measurements (6 depths);
- water sampling (3 depths);
- mini-frac (1 depth in Röt Clay and 1 depth in Lower Bunter Sands); and
- the Vertical Interference Tests (VIT) (3 depths).

Measurements associated with the highest tool running speeds include:

- logging head thermometer measurements – made after a short circulation time and could therefore have been affected by frictional heat generated during drilling as well as the relatively low volume of drilling fluid used which had insufficient time to cool at the surface; and
- quartz gauge measurements – MDT short duration points (20 depths)

The MDT long duration temperature measurements are considered most representative of the geothermal gradient and a plot of the data is shown in Figure 5.1.

Re-arranging the equation shown on this figure gives:

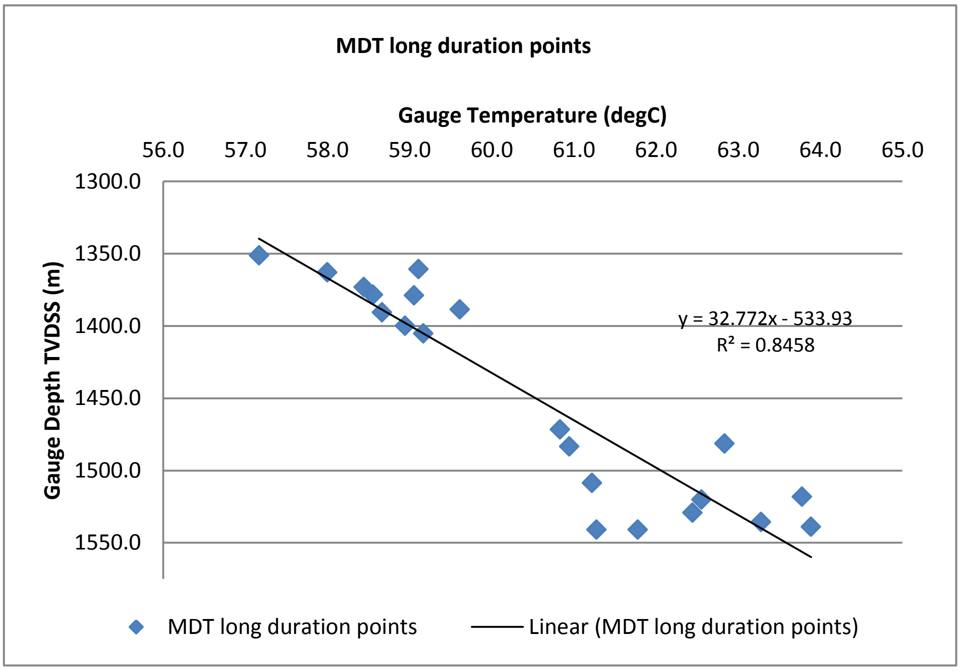
$$T_C = 0.0305D + 16.29$$

where:

T_C Temperature in °C
D True Vertical Depth Sub-Sea (TVDSS) in m.

In the above equation, the temperature gradient within the Endurance Bunter Sandstone Formation is estimated as 3.05°C/100m and this equates to a temperature of 55.9°C at a reference depth of 1300m TVDSS.

Figure 5.1: Temperature Gradient Measured in 42/25d-3



Temperature gradient from the MDT long duration test is considered most representative because it incorporates the largest set of data points of all temperature measurements for the tools given the most time at any given depth. It is also consistent with the data set that has been used for predicting pore pressures within Endurance as discussed in the next section.

Figure 5.2 shows a regional geothermal gradient derived from a plot of bottom hole temperatures calculated in wells within the area around the Endurance structure whilst Figure 5.3 shows a comparison of this regional gradient with two other gradients generated from well 42/25d-3 data. The geothermal gradient of the 'All well (42/25d-3) data' plot is 3.69°C/100m and incorporates data from the well test, the Wireline Head Thermometer and the MDT measurements and includes an assumed seabed temperature of 10°C. The 'All well data' plot is not considered representative because of the limited data points, issues with tool malfunction and the insufficient time available during measurement for the tools to stabilize to formation temperature. The regional data, on the other hand, can be misleading due to the different lithologies found at equivalent TVDSS.

Figure 5.2: Bottom Hole Temperature Calculated From Nearby Wells

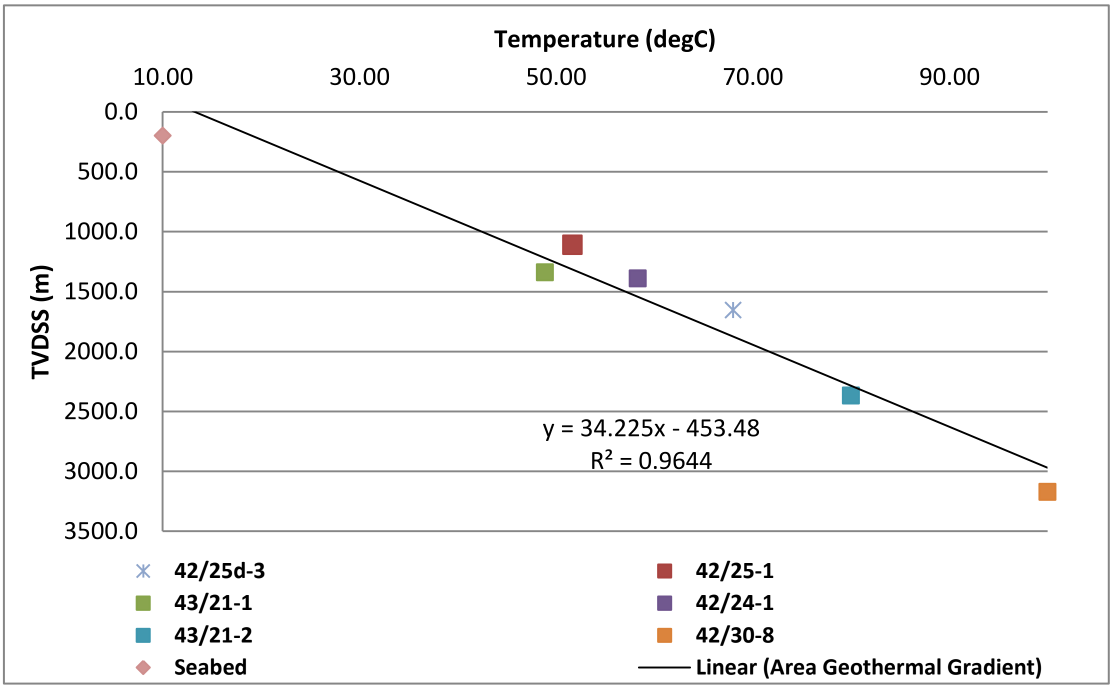
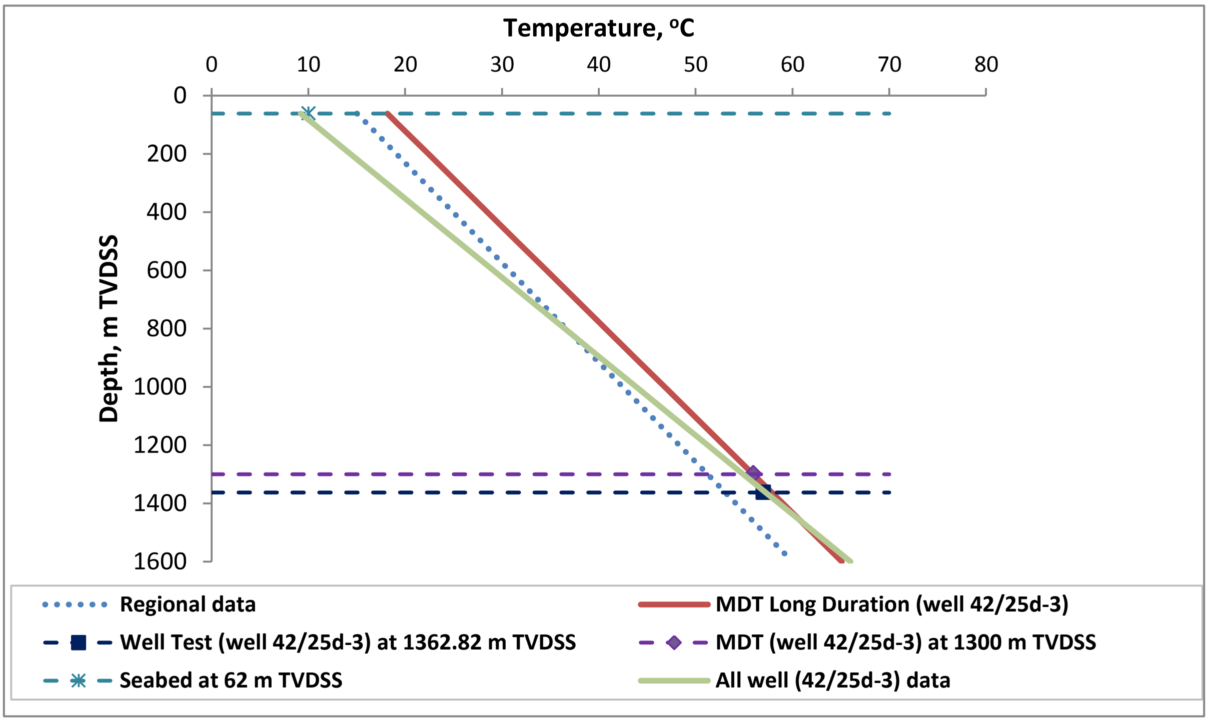


Figure 5.3: Comparison of Endurance Temperature Measurements



5.2 Pore Pressure Prediction

Knowledge of formation pressure is useful for anticipating potential bore hole stability problems and to design suitable mitigation measures. For formations that have not been penetrated by wells, a number of methods were developed for inferring pore pressures. These usually fell into two broad approaches:

1. direct methods – the use of crossplots or overlays to estimate pore pressure deviation from a designated normal pressure trend line;
2. effective stress methods – based on the interpretation of stress change effects; compaction and changes in elastic wave velocities, as only a function of the vertical effective stress (σ) according to the relation.

$$\sigma = S - P$$

where:

σ vertical effective stress
S total vertical stress
P pore pressure

As the Endurance structure has been penetrated by three wells, two of which have had direct pore pressure measurements, and given that all available information from Endurance suggest that it is highly unlikely that the Bunter Sandstone is compartmentalised, standard pore pressure prediction techniques were not required for the Endurance structure. Instead, the combined plot of the RFT pressure data from well 42/25-1 and the long duration MDT pressure data from well 42/25d-3 in Figure 5.4 shows that the pressure gradient within Endurance is well behaved and can be approximated as 0.1147 bar/m across the Bunter Sandstone reservoir.

From Figure 5.4 the MDT pressure data, can be stated as

$$P = 0.1147Z - 8.7057$$

where:

P pore pressure [bar] at a given depth Z [m TVDSS]

Therefore, the pore pressure at 1405.3m TVDSS, which is the midpoint of perforations for the well test performed in the 42/25d-3 appraisal well, is calculated as 152 ±0.5 bar. This is in agreement with the calculated final pressure at the end of the well test build-up period of 151.8 bar at the same depth.

A comparison of the MDT and well test pressure data is shown in Figure 5.5.

Figure 5.4: RFT Pressure Data from 42/25-1 and MDT Pressure Data from 42/25d-3

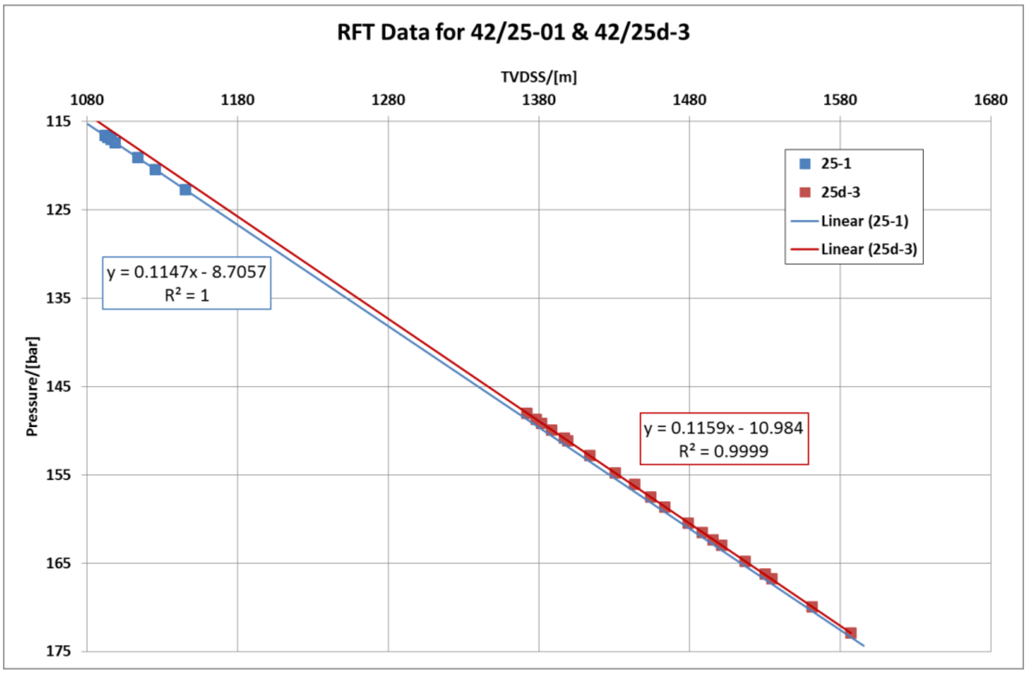
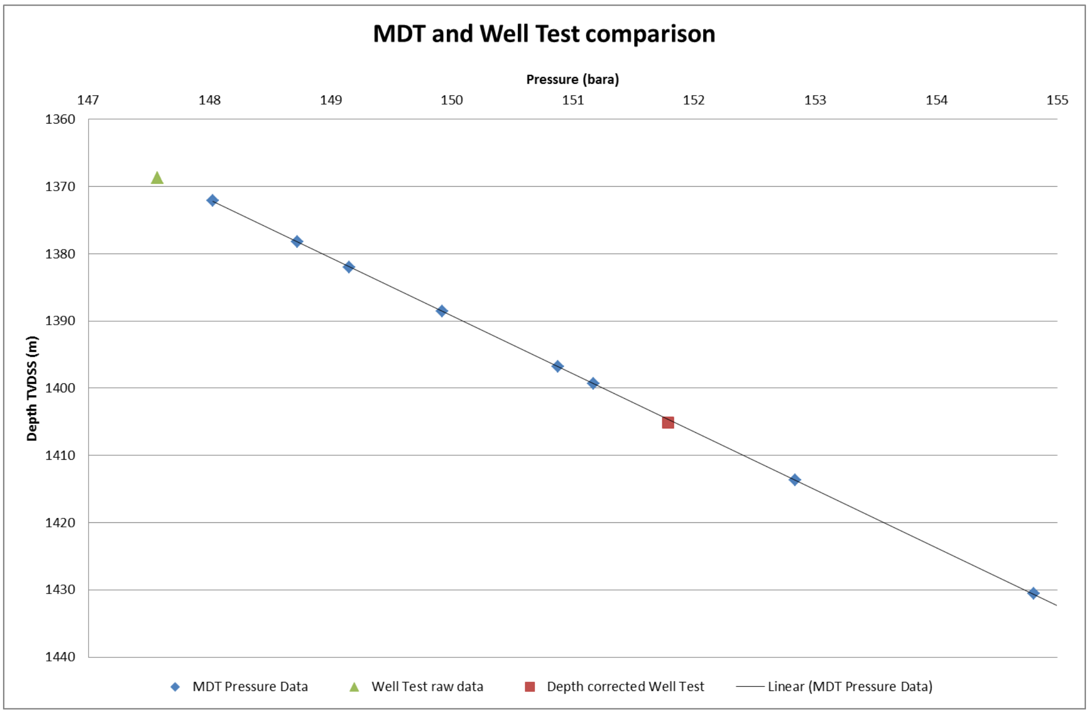


Figure 5.5: Comparison of Well Test and MDT Pressure Data



6 Injectivity and Thermal Fracturing Analysis

An inflow and tubing performance model was built to determine the bottom hole injection (pressure and temperature) conditions for a variety of perforation intervals in the six zones (L3B, L3A, L2B, L2A, L1B and L1A) identified within the Bunter. This was modelled using the PROSPER software tool.

This information was then used in determining the probability and extent of any fracturing using MPwri software. In order to ascertain the impact on the near wellbore formation from the injection of cold CO_2, a fracture model has been developed (using the MFrac design and evaluation simulator software for fracture design and treatment analysis) with the objective of assessing:

- the potential for the extent of fracturing in the Bunter Sandstone Formation; and
- the impact of fracturing on inflow performance.

6.1 PROSPER Modelling

PROSPER models were used to assess the well system performance (vertical lift and inflow). A total of six models were created in order to assess the different zones identified within the Bunter Sandstone. These zones exhibit slightly different properties in terms of thickness, pressure, temperature, permeability and porosity. Each will have an impact on both the inflow performance and fracturing propensity.

6.1.1 Formation Properties

The formation properties used in both the PROSPER model and the MFrac model are shown in Table 6.1. These properties were taken from an average of offset well data currently employed in the static (Petrel geological) model. Note the decreasing permeability and porosity with depth. The measured depth is from the well trajectory.

Table 6.1: Bunter Formation Properties Used in the Modelling

Bunter Zone	Top (mMD)	Thickness (m)	Pressure (bar)	Temperature (°C)	Permeability (mD)	Porosity (Fraction)
L3B	1751.7	24.2	130.8	56.2	1760	0.28
L3A	1775.9	38.4	132.8	56.6	725	0.24
L2B	1814.3	102.5	136.0	57.7	710	0.24
L2A	1916.7	97.0	142.9	59.9	570	0.23
L1B	2013.7	110.2	150.6	62.4	200	0.20
L1A	2123.9	105.4	159.5	65.2	100	0.18

6.1.2 Well Trajectory and Construction

The well details were based on designs outlined in the drilling plan Note that PROSPER only allows for 20 rows of well trajectory data using measured depth, true vertical depth and angle, so the input data was edited to remove sections of the well profile which remained constant.

The trajectory used for modelling the tubing performance is shown in Figure 6.1.

Figure 6.1: Injection Well Trajectory from 42/25d-D W1

Input Data

Point	Measured Depth (m)	True Vertical Depth (m)	Cumulative Displacement (m)	Angle (degrees)
1	0	0	0	0
2	196.6	196.6	0	0
3	214.9	214.9	0	0
4	241.7	241.7	0	0
5	304.8	304.5	6.14573	5.58928
6	394.7	391.7	28.0128	14.0777
7	424.9	420	38.5556	20.4322
8	454.8	446.8	51.8134	26.3214
9	484.9	474.6	63.3534	22.5436
10	514.8	500.8	77.7606	28.8062
11	574.9	551.1	110.653	33.1818
12	604.7	574.5	129.105	38.2576
13	634.9	597.4	148.794	40.6873
14	664.8	619	169.468	43.7463
15	681.8	630.9	181.609	45.573
16	724.8	659	214.157	49.1948
17	737.6	666.9	224.228	51.8889
18	755	677	238.397	54.5171
19	761.7	680.9	243.845	54.4023
20	2293.9	1560	1498.76	54.9878

In order to have a more accurate assessment of the changes in pressure and temperature along the wellbore and hence at the bottom hole conditions, a full enthalpy balance model was selected in PROSPER. This type of model requires additional input for the well construction and lithological parameters in order to accurately determine U-values and thus heat transfer.

The input data was taken from the drilling design and prognosed lithology presented in the drilling plan and is shown in Figure 6.2 and Figure 6.3. Lithological (rock formation) properties are shown in Figure 6.4.

The tubing size was 5½in tubing throughout.

Figure 6.2: Well Drilling and Casing Data

Drilling Details

Point	Drilling Depth (m)	Hole Diameter (inches)	Casing Shoe Depth (m)	Casing Outside Diameter (inches)	Casing Weight (lb/ft)	Top Cement Depth (m)	Casing Top Depth (m)	Mud Density (lb/US gal)
1	164.4	36	163.9	30	310	93.9	93.9	8.34
2	172.7	26	172.2	20	133	163.9	163.9	8.34
3	671	17.5	670.5	13.375	68	93.9	0	9.75
4	1646.4	12.25	1645.9	9.625	53.5	93.9	0	11.25
5	2292.6	8.5	2292.1	7	29	1493.5	1493.5	10.25
6								
7								
8								
9								
10								

Figure 6.3: Lithological Data

Lithology

Point	Formation Type	Bottom Depth (m)	Shaliness (fraction)	Porosity (fraction)	Permeability (md)	Rock Consistency	In Situ Fluid	Salinity (ppm)
1	Shale	770						
2	Anhydrite	948						
3	Shale	1216						
4	Halite	1732.5						
5	Shale	1751.7						
6	Sandstone	2229.3	0.1	0.2	150	Consolidated	Water	300000
7	Shale	2292						
8								
9								
10								

The heat transfer properties used for each of the formations identified above used the defaults defined in the PROSPER model, as listed in Figure 6.4.

Figure 6.4: Rock Properties for Heat Transfer Calculations

Rock Type	Rock Density	Rock Conductivity	Specific Heat Capacity
	g/cc	W/m/K	KJ/Kg/K
Sandstone	2.65	1.83458	0.76618
Shale	2.4	1.21151	0.93784
Limestone	2.71	0.9346	0.84573
Dolomite	2.87	1.73073	0.91691
Halite	2.17	4.84606	0.91691
Anhydrite	2.96	1.29805	1.1095
Gypsum	2.32	1.29805	1.08438
Lignite	1.5	3.46147	1.25604
Volcanics	2.65	2.76918	0.83736
Fixed Value	2.61	1.90381	0.83736

6.1.3 System Performance Sensitivities and Results

A sensitivity test was carried out to the length of the perforation interval for each of the six defined layers within the sandstone to establish the impact on inflow and bottom hole injection properties of the CO_2.

The perforation intervals were 5m, 10m, 20m, 30m and 50m and were are located such that their midpoint was at the midpoint of one of the six layers. Note that due to the thickness of L3B and L3A, 30m and 50m sensitivity tests were not included.

The input parameters for each of the sensitivities were:

- wellhead injection pressure 82bar;
- injected fluid temperature 5°C (at the wellhead);
- injected fluid rate 141MMscf/day (2.7MTPA); and
- skin 0, note that a positive skin effect indicates extra flow resistance near the wellbore, and a negative skin effect indicates flow enhancement near the wellbore.

The results of the PROSPER modelling are shown in Table 6.2 and Table 6.3. As the thickness of the L3B formation was less than 30m, analysis of injectivity was not carried out for the 30m and 50m perforated cases. Similarly, for L3A the 50m case was not assessed.

Table 6.2: VLP System Injection Rates in MMscf/day (MTPA)

Bunter Zone	Perforated Interval				
	5m	10m	20m	30m	50m
L3B	138	149	152	-	-
L3A	115	135	142	144	-
L2B	125	149	157	159	160
L2A	114	140	150	152	153
L1B	73	103	122	127	130
L1A	47	70	87	92	95

Remember that these values are for a skin of 0. It is unlikely, for example, that 20m of perforations in L3A will result in an injectivity of 142MMscf/day.

Using this example, with a skin of 0, 5, 10 and 20, the following reductions in inflow performance are seen:

- L3A 20m perfs 0 skin 142MMscf/day;
- L3A 20m perfs 5 skin 131MMscf/day;
- L3A 20m perfs 10 skin 120MMscf/day; and
- L3A 20m perfs 20 skin 100MMscf/day.

It is important to understand the bottom hole conditions during injection for input into the fracturing model. Table 6.3 lists the pressures, temperatures and fluid density taken from the gradient survey for each of the various layers.

Table 6.3: Bottom Hole Injection Conditions @141 MMscf/day (2.68 MTPA)

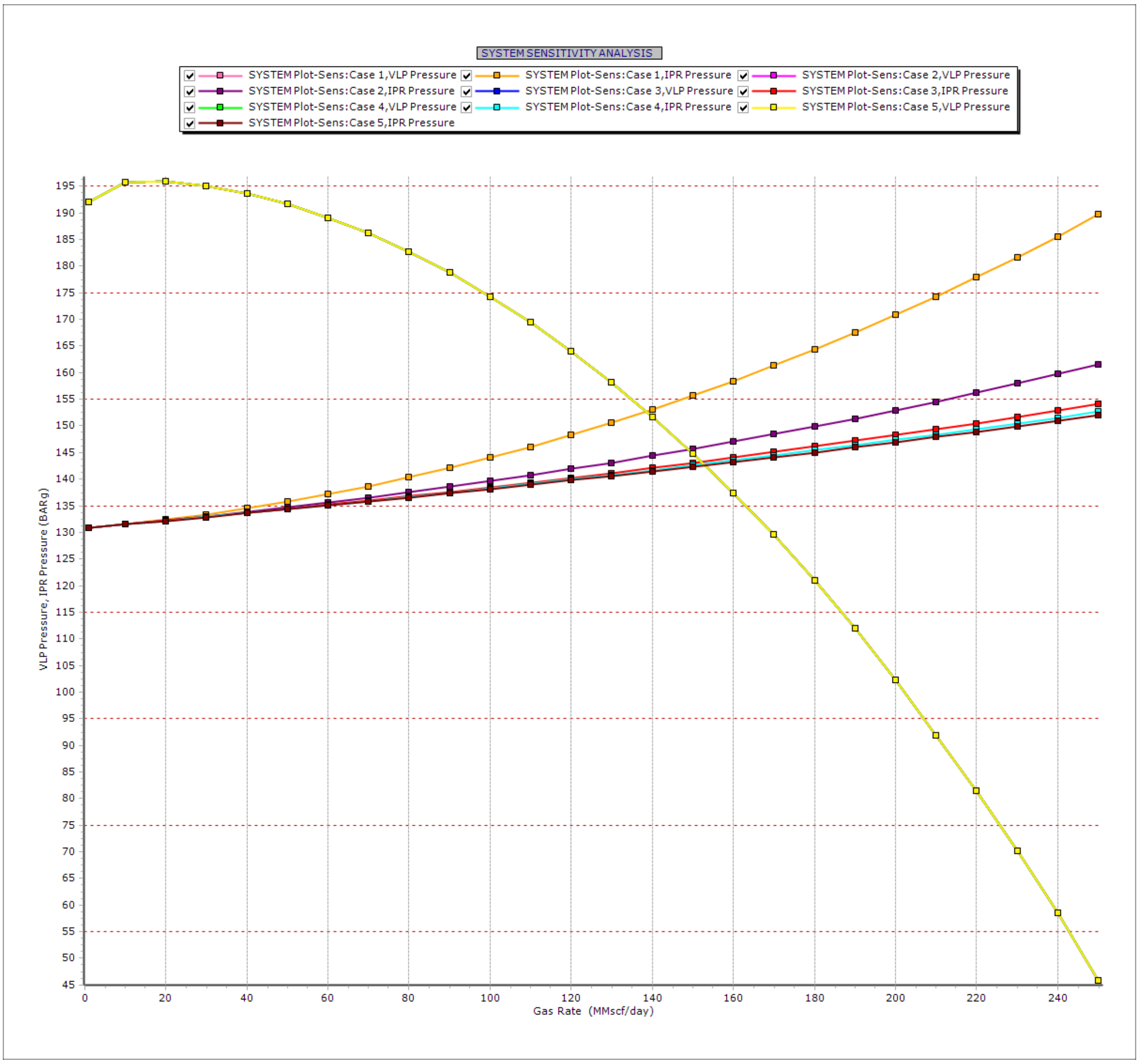
Bunter Zone	Reservoir Pressure (bar)	Bottom Hole Injection Pressure (bar)	Change in Pressure ΔP (bar)	Bottom Hole Injection Temperature (°C)	Fluid Density (kg/m^3)
L3B	130.8	150.52	19.7	14.0	935.3
L3A	132.8	152.43	19.6	14.3	935.2
L2B	136.0	155.52	19.5	14.7	934.9
L2A	142.9	159.91	17.0	15.4	934.5
L1B	150.6	164.46	13.9	16.1	934.1
L1A	159.5	169.20	9.7	17.1	933.6

By comparison, work presented by Genesis indicated that bottom hole temperatures would vary between 10°C and 27°C depending on reservoir pressure, injection rate and season. However it is noted that in some cases the selection of a wellhead temperature is significantly different from that used in this analysis; WHIT ranges from 1.2°C to 10.6°C in winter. Given the length of the subsea pipeline, the arrival temperature of the CO_2 at the wellhead will not be related to the rate or exit temperature of the CO_2 compressor/pump and will only be a function of the seasonal change of the seabed temperature.

The following pages (Figure 6.5 to Figure 6.10) present the system curves for each of the layers showing the inflow performance based on the perforated interval. Note that because this is an injection well, the Inflow Performance Relation (IPR) curves increase as they move to the left of the graph while the Vertical Lift Performance (VLP) curve (yellow line) decreases.

Note that there is a decreasing rate of return in terms of inflow and perforation interval, with little difference being seen in terms of injectivity between 30m and 50m.

Figure 6.5: Bunter Layer L3B System Performance Curves



Due to the high average permeability in layer L3B, the inflow performance is high even for short perforated intervals. However, due to the possibility of fracturing this zone, it is not recommended that it should be perforated at the outset.

Figure 6.6: Bunter Layer L3A System Performance Curves

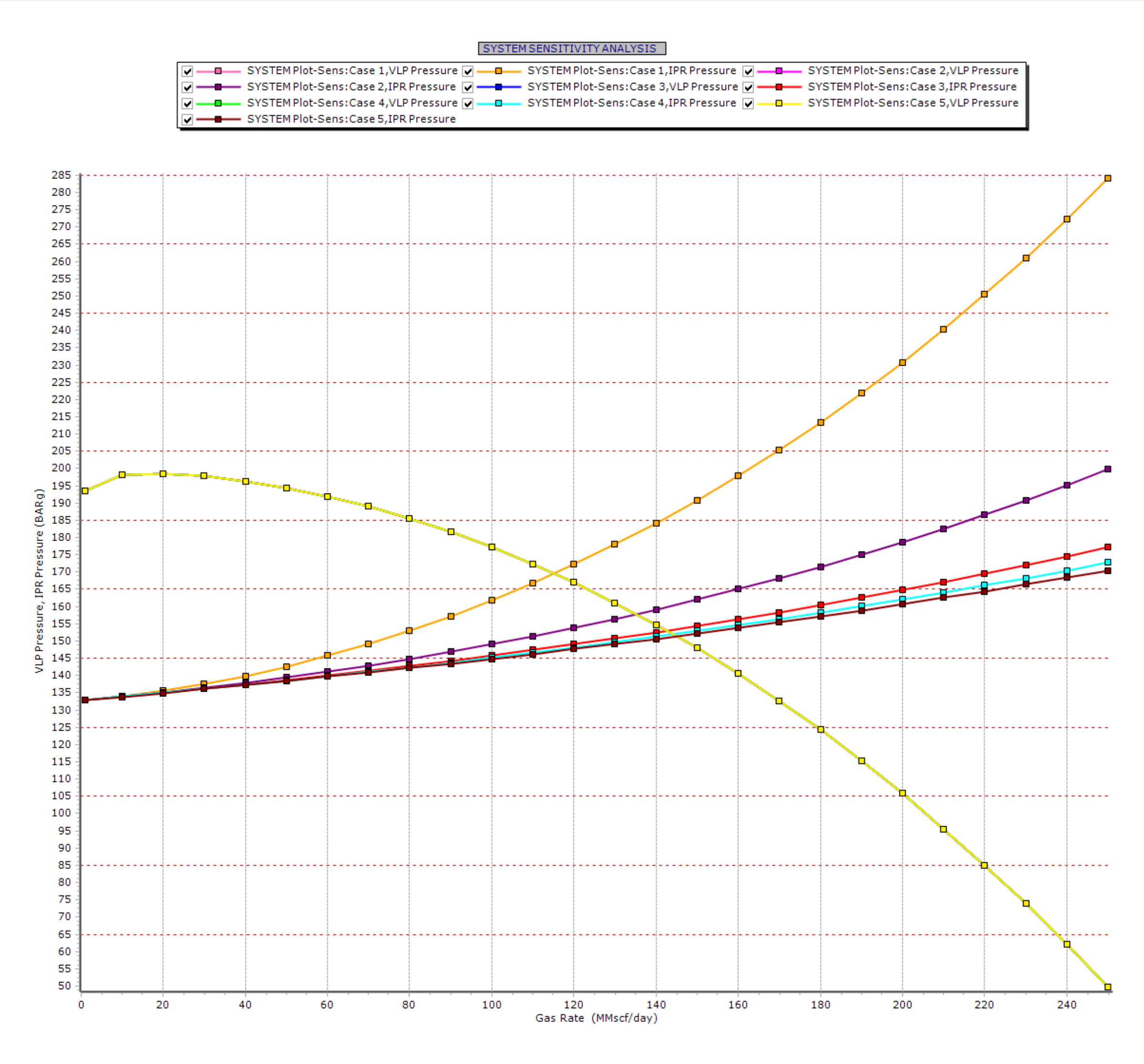


Figure 6.7: Bunter Layer L2B System Performance Curves

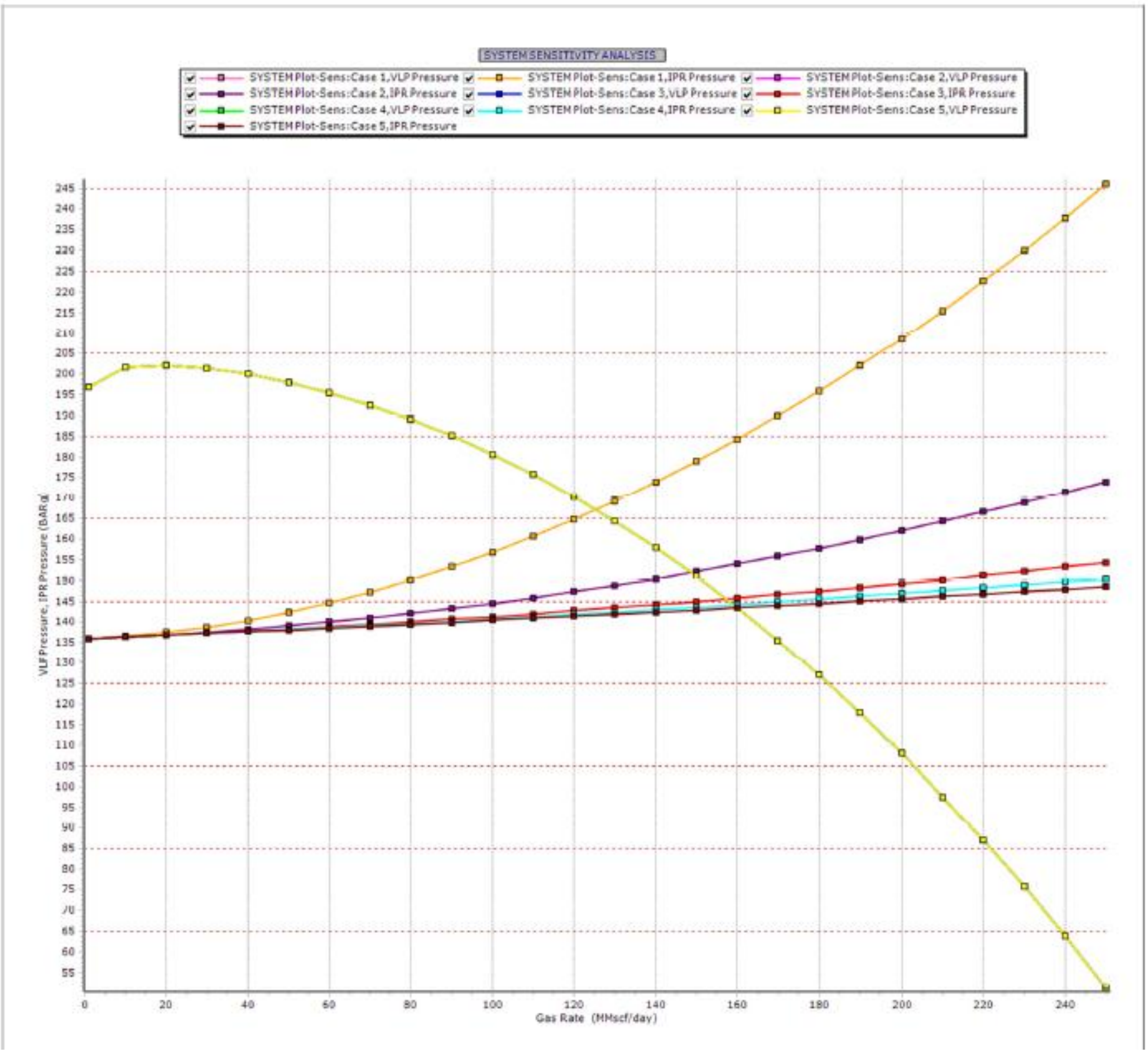


Figure 6.8: Bunter Layer L2A System Performance Curves

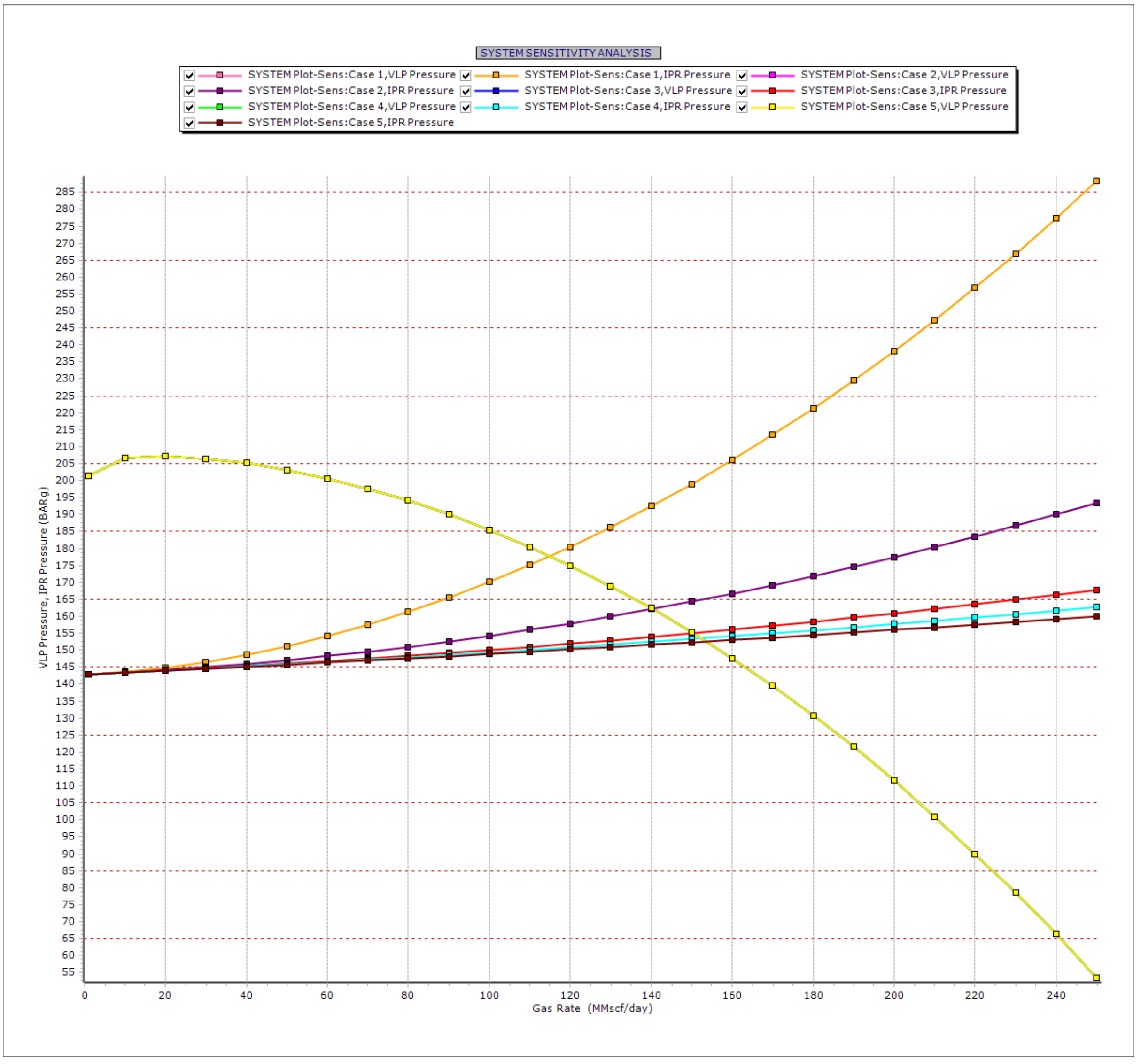
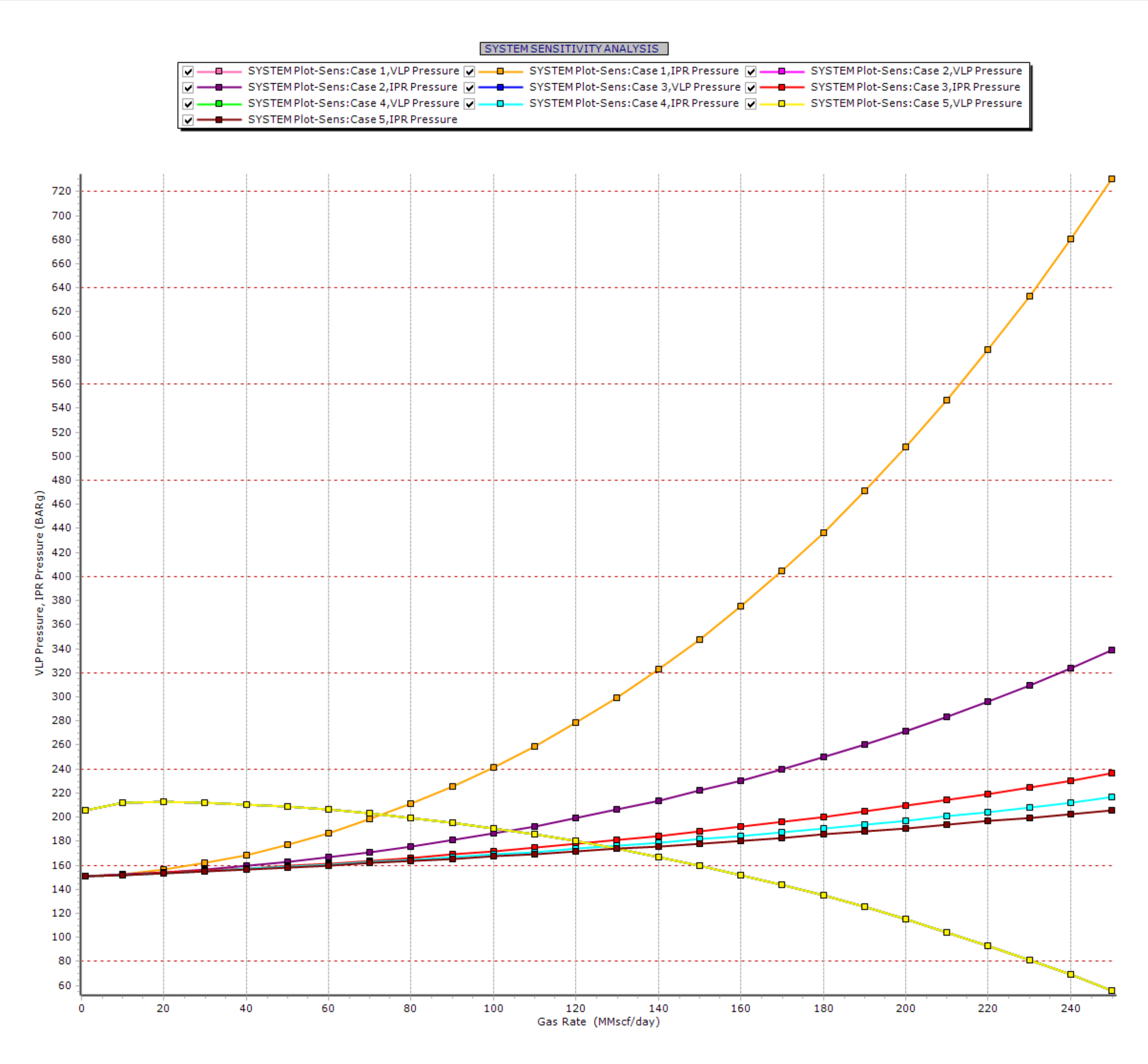
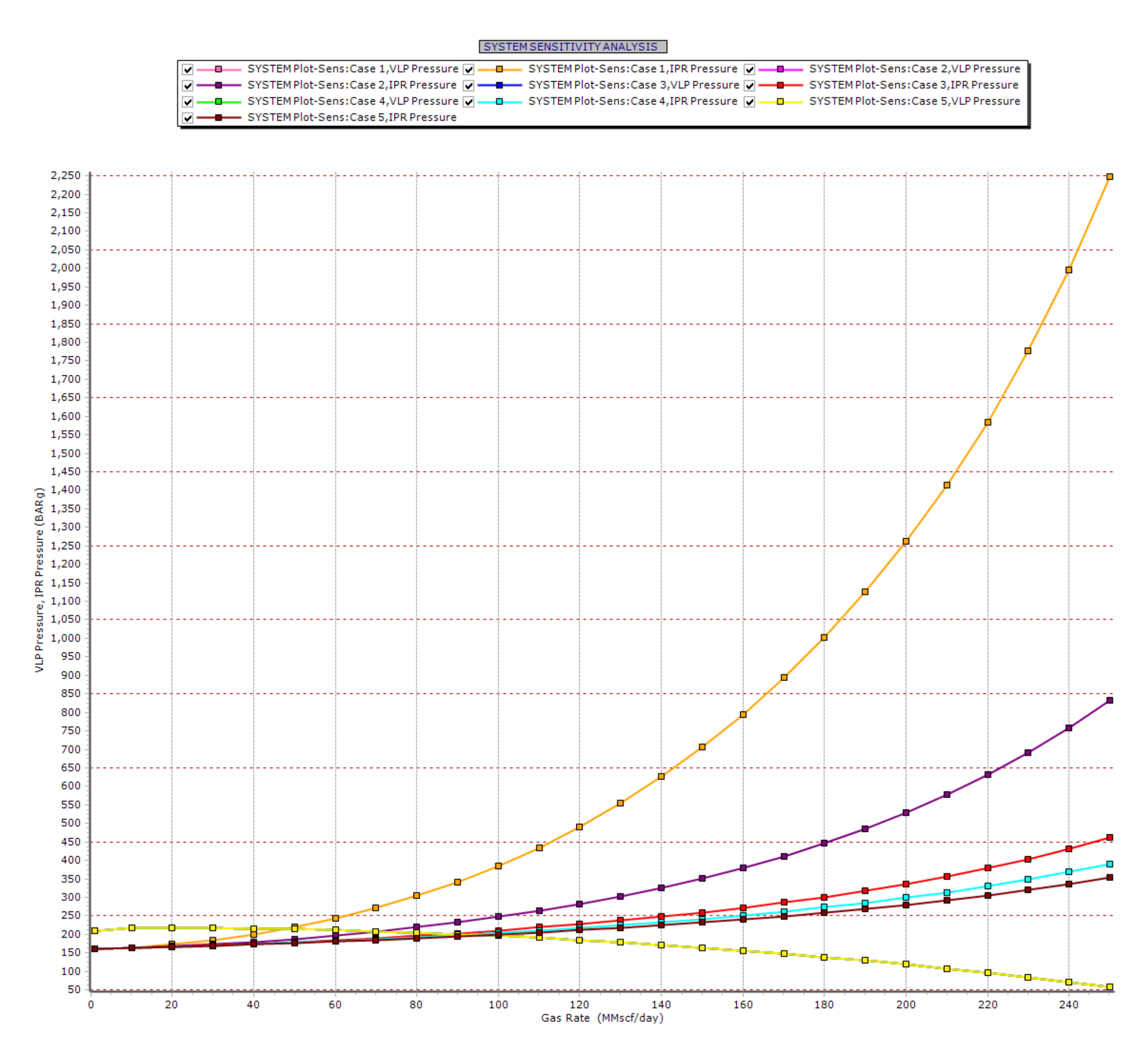


Figure 6.9: Bunter Layer L1B System Performance Curves



Note that the inflow curve here is very low and shallow due to the low average permeability in this layer and thus a greatly reduced injectivity even for a 50m perforated interval.

Figure 6.10: Bunter Layer L1A System Performance Curves



Note that the inflow curve here is very low and shallow due to the low average permeability in this layer and thus a greatly reduced injectivity even for a 50m perforated interval.

Looking at the injectivity requirement, and the impact of skin, consideration should be given to perforating in both the L1B and L1A zones of the Bunter Sandstone. This would:

- ensure adequate injectivity;
- allow for future perforating further up the well should perforations collapse or the formation become damaged; and
- minimise the chances of thermal fracturing compromising the seal (caprock) integrity.

6.2 Fracture Modelling

6.2.1 Introduction

Three aspects of fracture modelling have been considered during the FEED work. They are:

3. fracturing of the primary seal/cap rock;
4. near well thermal stress induced fracturing; and
5. near well hydraulically induced fracturing.

The first is a function of the average pressure and temperature in the reservoir; the second two are a function of the injection of CO_2 and are local to the perforations through which the CO_2 is injected from the wells to the reservoir.

The perforating strategy is to perforate only the deeper half of the wells within the reservoir zone. This strategy is for two reasons, firstly to optimise the solution storage of CO_2 in the formation brine and secondly to minimise the cooling of the primary seal formations the cooling of which may slightly weaken their pressure competence.

The injected CO_2 is generally cooler than the reservoir rock, but the minimum expected bottom hole injection temperature is 20°C compared to the reservoir temperature of 60°C. This temperature difference in conjunction with the overpressure caused by the injection results in thermally induced fractures. Hydraulically induced fractures can occur without any thermal stress and, in this case depend on the over pressure in the near wellbore region. The higher the native permeability and the longer the perforated interval, the lesser will be the hydraulically induced fractures. Until the injection wells are drilled and a precise evaluation of the local permeability is made the extend of these fractures will not be known but in all cases can be expected to have less than 100m horizontal and 10m vertical extent under the highest thermal stress condition. Clearly then, these fractures will not affect the cap rock/seal.

The modelling of the cap rock/primary seal fracturing is based on the geomechanical model and the overall average pressure predicted by the simulation model. Even in the worst case sensitivities using zero adhesion fracture surfaces and where a weakening of the caprock occurs as a result of the cooling of it by the injected CO_2, no adverse effects are predicted.

6.2.2 Endurance Model

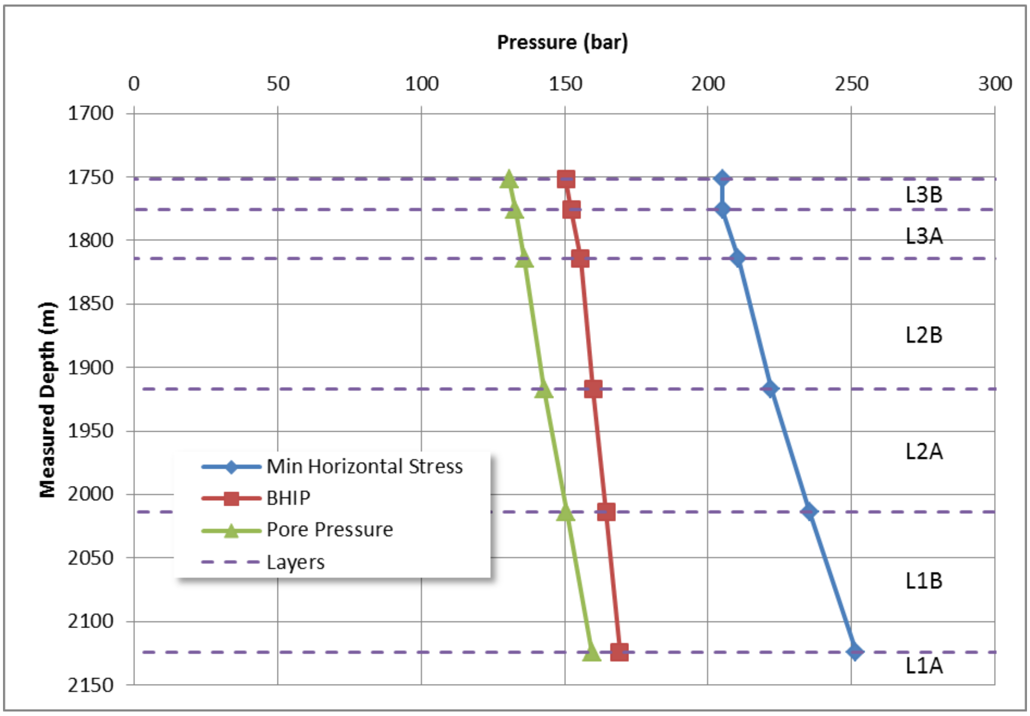
Fracture modelling was carried out using the MPwri which is software designed for evaluating the effects of injecting large volumes of fluid over long periods of time with fracture efficiencies approaching zero. MPwri is very similar to MFrac, but includes thermos-elastic and poro-elastic components and is designed for analysing the long term injection of fluids. The rock properties used in the model are shown in Table 6.4 and were taken from the model developed in VISAGE. Note that VISAGE is a finite-element geomechanics simulator, which models problems to enable the planning and mitigation of risks, is part of the Petrel software platform.

Table 6.4: Endurance Geomechanical Properties

Zone	Effective σh (bar)	Total σh (bar)	Stress Gradient (bar/m)	Young's Modulus (bar)	Poisson's Ratio
Röt Halite	120.3	235.0	0.211	82233	0.38
Röt Clay	101.8	224.7	0.186	138600	0.25
L3B	74.2	205.0	0.168	102400	0.26
L3A	72.3	205.1	0.168	95800	0.26
L2B	74.6	210.6	0.169	104600	0.25
L2A	79.1	221.9	0.173	105900	0.25
L1B	84.7	235.4	0.174	113600	0.25
L1A	91.8	251.4	0.177	116500	0.24
Bunter Shale	143.8	301.1	0.202	164000	0.24

As a sense check the bottom hole injection pressures were plotted, see Figure 6.11 in conjunction with the reservoir pressure and stress data from Table 6.4. The table shows that the bottom hole injection pressure is, in all cases lower that the minimum horizontal stress – suggesting that fracturing will not be an issue. However, this does not take into account any thermal effects that will occur as a result of introducing cold CO_2 into a hot formation.

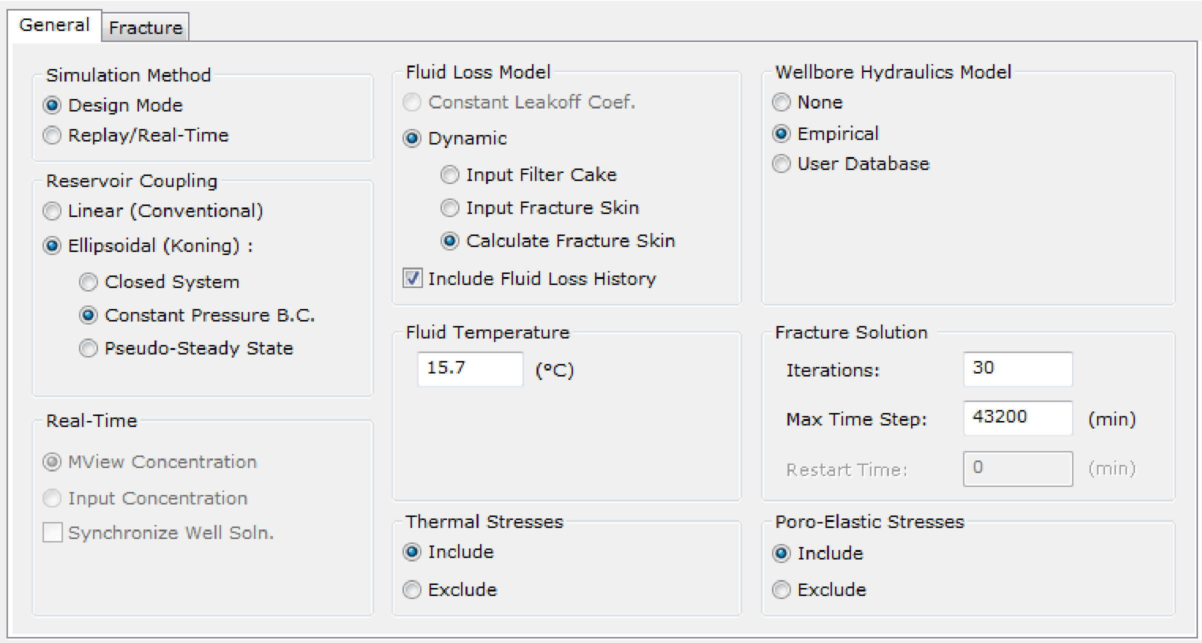
Figure 6.11: Reservoir Pressure, BHIP and Min Horizontal Stress



6.2.3 Fracturing Data Input

The fracture model was developed with an ellipsoidal (2D fluid loss model) with dynamic fluid loss (based on a calculated fracture skin) and thermal and poro-elastic components. In order to allow the injectivity to run for 20 years, all options selected for the model in MPwri are shown in Table 6.5.

Figure 6.12: General Fracture Model Options



A total of five fracturing models were developed to allow for analysis of injection for different perforated intervals into each of the six layers. The tops and bottoms of these layers are shown in Table 6.5. Note that a 30m and 50m interval in layer L3B and a 50m interval in layer L3A extends out of the interval so this has not been considered.

Table 6.5: Top and Bottom Measured Depth of Perforated Intervals per Layer

Zone	Mid Formation (mMD)	Top and Bottom (Bott) of Perforated Interval (mMD)									
		5m		10m		20m		30m		50m	
		Top	Bott	Top	Bott	Top	Bott	Top	Bott	Top	Bott
L3B	1763.8	1761.3	1766.3	1758.8	1768.8	1753.8	1773.8	-	-	-	-
L3A	1795.1	1792.6	1797.6	1790.1	1800.1	1785.1	1805.1	1780.1	1810.1	-	-
L2B	1865.5	1863.0	1868.0	1860.5	1870.5	1855.5	1875.5	1850.5	1880.5	1840.5	1890.5
L2A	1965.2	1962.7	1967.7	1960.2	1970.2	1955.2	1975.2	1950.2	1980.2	1940.2	1990.2
L1B	2068.8	2066.3	2071.3	2063.8	2073.8	2058.8	2078.8	2053.8	2083.8	2043.8	2093.8
L1A	2176.6	2174.1	2179.1	2171.6	2181.6	2166.6	2186.6	2161.6	2191.6	2151.6	2201.6

The treatment schedule is based on injection of CO_2 at a rate of 2.68MTPA for a period of 20 years.

For the purposes of input, this was converted into a volumetric rate in m^3/min.

2.68 MTPA = 2,680,000,000kg/yr = 5,099kg/min. The bottom hole injection pressure from the PROSPER model was an average of 934.6kg/m^3 (Table 6.3) so the injection rate used throughout was 5.45m^3/min.

6.2.4 Fluid Loss Parameters

Figure 6.13: Fluid Loss Parameters

Lithology Symbol	Zone Name	TVD at Bottom (m)	MD at Bottom (m)	Reservoir Pressure Gradient (bar/m)	Reservoir Pressure (bar)	Total Compres. (1/bar)	Permeability (mD)	Total Porosity (fraction)
	Rot Halite	1249.37	1744.8	0.091246	114	0.00043511	0.1	0.01
	Rot Clay	1253.33	1751.71	0.0981386	123	0.00043511	0.01	0.01
	L3B	1267.21	1775.91	0.102588	130	0.00043511	1760	0.28
	L3A	1289.23	1814.3	0.102387	132	0.00043511	725	0.24
	L2B	1347.97	1916.71	0.100151	135	0.00043511	710	0.24
	L2A	1403.6	2013.7	0.101168	142	0.00043511	570	0.23
	L1B	1466.81	2123.9	0.102263	150	0.00043511	200	0.2
	L1B	1527.27	2229.31	0.104107	159	0.00043511	100	0.18
	Bunter Shale	1539.14	2250	0.102005	157	0.00043511	0.01	0.01

6.2.5 Consistency with VISAGE

The VISAGE model assumes an average inflow across the entire Bunter. Under such conditions, no fracturing is noted. A similar analysis was carried out in MPwri to ensure that if the entire interval was perforated that no fracturing would occur and this was found to be the case.

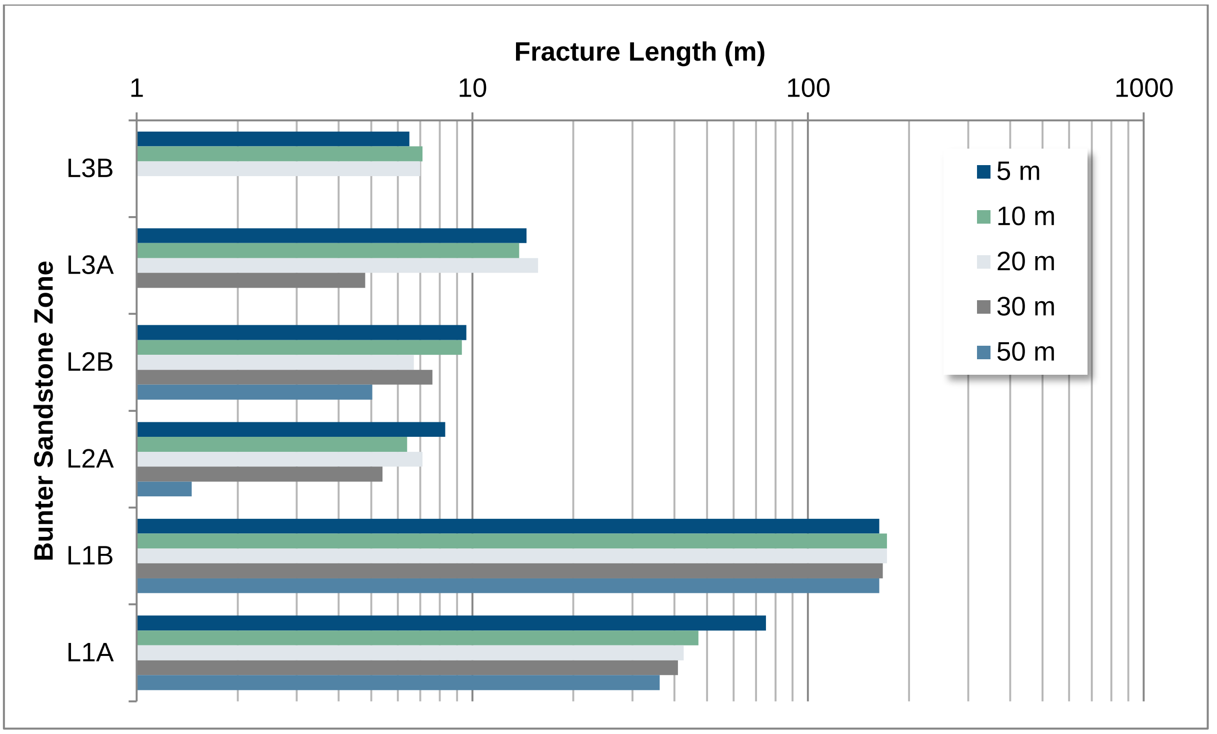
6.2.6 Base Case Results

The base case is considered to be injection into each layer separately with a limited perforation interval as noted previously; 5m, 10m, 20m, 30m and 50m. The results give the fracture lengths shown in Table 6.6 and Figure 6.14.

Table 6.6: Base Case Fracture Properties

Zone	Perforated Interval				
	5m	10m	20m	30m	40m
L3B	6.5	7.1	7	-	-
L3A	14.5	13.8	15.7	4.8	-
L2B	9.6	9.3	6.7	7.6	5.03
L2A	8.3	6.4	7.1	5.4	1.46
L1B	163	172	172	167	163
L1A	75.0	47.2	42.6	41.0	36.5

Figure 6.14: Comparison of Fracture Lengths and Perforated Intervals



A number of things should be noted about these results:

- due to the long period of continuous injection assumed for the base case, fracturing is not greatly affected by the length of the perforation intervals;
- the exceptionally large fracture intervals seen in layers L1B and L1A, which are a result of the combined increase in Young's modulus for these zones along with a significant reduction in permeability; the long period of continuous injection impacts on the fracture length; and
- in all cases the height of the fracture is contained within the injected zone.

Typical times to reach the full fracture length are between 12 years and 17 years, although in L1B extension was still continuing at the 20 year shut-off period. The volume of the cooled region is defined by:

$$V_c = \frac{(\rho c)_w V_i}{(\rho c)_r (1-\varphi) + (\rho c)_w \varphi (1 - S_{or}) + (\rho c)_o \varphi S_{or}}$$

where:

Vc	volume of cooled zone;	φ	Porosity;
ρ	density (w = water, r = rock, o = oil);	Vi	Volume of injected fluid;
c	compressibility (w = water, r = rock, o = oil); and		
Sor	residual saturation of the in-situ fluid.		

The cooled region is approximated to an elliptical inclusion with volume Vc. Reduced porosity and hence permeability will result in a more rapid expansion of the cooled zone as the total volume of the fluid will have to travel further to achieve the same volumetric input for the same rate of injection.

The governing equations for thermos-elastic and poro-elastic injection are based on numerical simulations. The average thermal stress perpendicular to the fracture face in the interior of an elliptical cooled region of any height is given by:

$$\frac{(1-\nu)\Delta\sigma_3|T}{E\beta\Delta T} = \mathcal{F}(a_0, b_0, h)$$

Where:

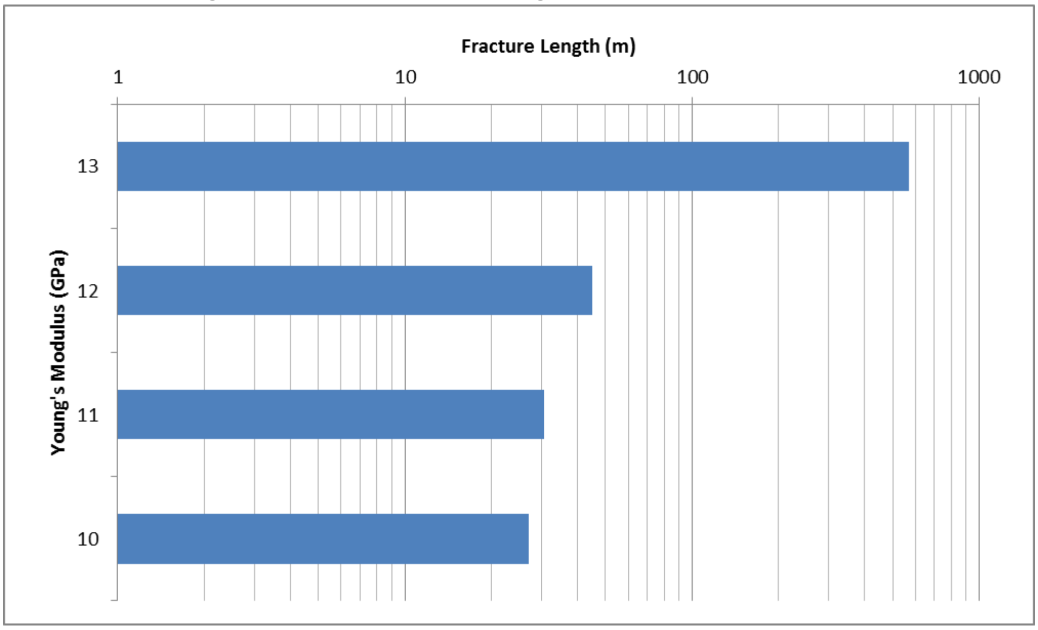
v	Poisson's Ratio;
Δσ3│T	change due to thermo-elastic stress;
E	Young's modulus;
β	matrix function;
ΔT	Temperature differential;
a0	major ellipsoidal thermal front axis;
b0	major ellipsoidal thermal front axis; and
h	height of fracture.

Where the function is the thermos-elastic coefficient related to the fracture length, width and height. The region of changed rock temperature is a sharp boundary interface which progresses outward in an ellipsoidal shape.

6.2.7 Sensitivity to Young's Modulus

Because of the excessive fracturing seen in the lower layers, two sensitivities were run. The first was against Young's modulus, since the average Young's modulus in the bottom two layers of the Bunter is higher than those seen in the overlying layers. From Figure 6.15 it can be seen that the facture length is very sensitive to changes in the Young's modulus.

Figure 6.15: Impact of Young's Modulus on Fracture Length

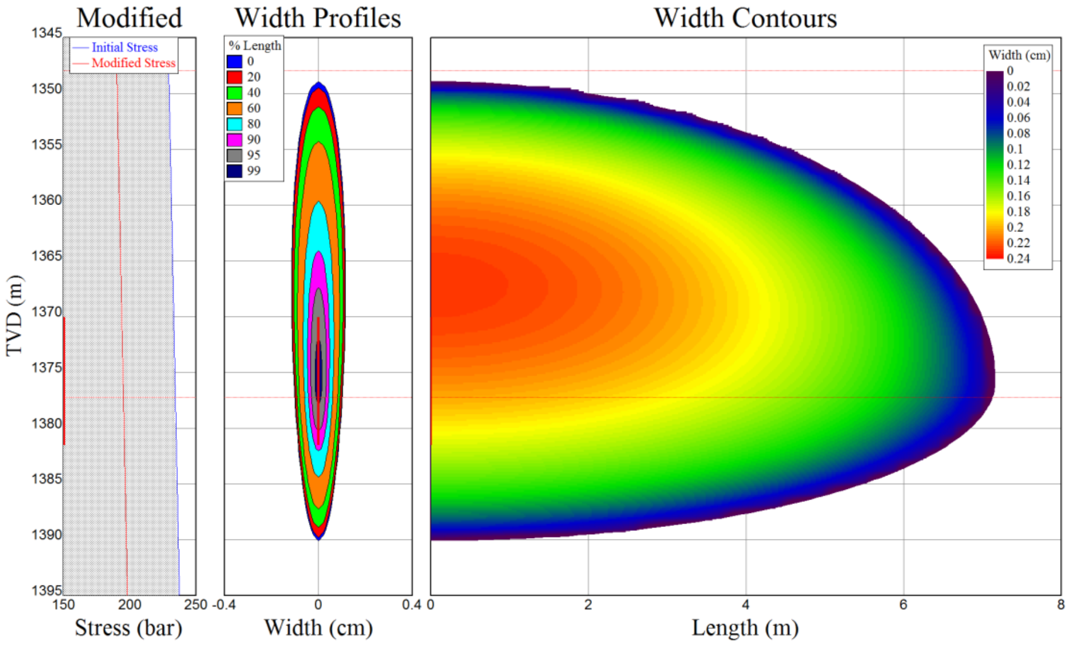


A second sensitivity, which accounted for no injection over a period of two months every year for twenty years, had no significant impact on the final fracture length, although the fracture closed during each shut-in period.

6.2.8 Shape of Fractures

The evolution of the fracture geometry is in line with what would be expected given a decreasing permeability and increasing Young's modulus with depth. The result is that the fracture tends to migrate upwards from the perforation interval (as per Figure 6.16).

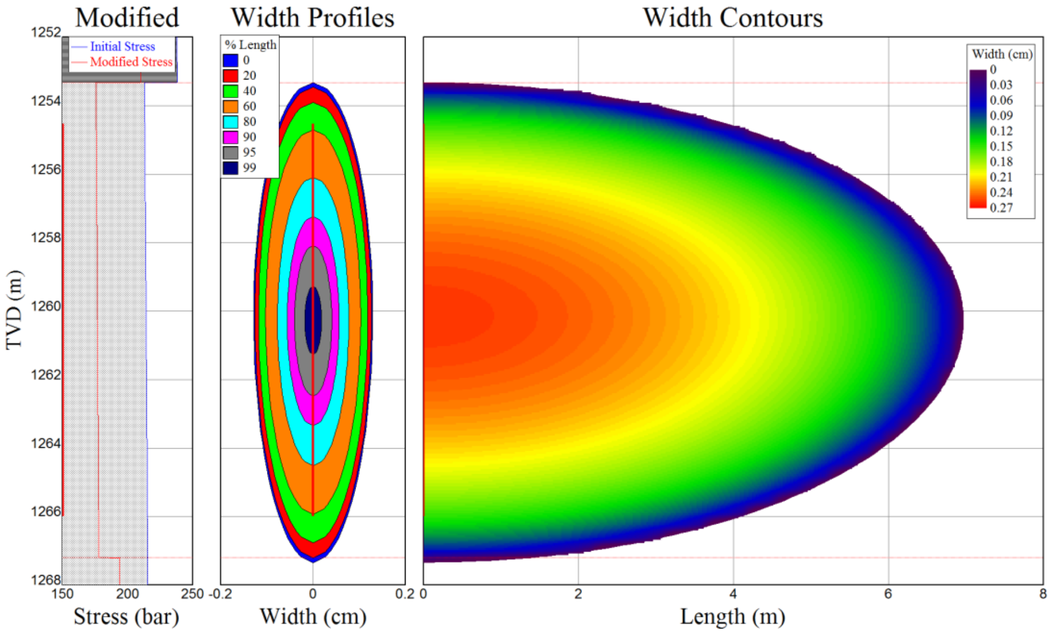
Figure 6.16: Typical Thermal Fracture in the Bunter



6.2.9 Fracturing in L3B

Fractures resulting from injection into the upper zone are contained within the zone as shown in Figure 6.17 However the fracture (in all perforated cases) does reach the base of the Röt Clay. As a result it would be expected that there would be a high rate of flow near the wellbore up to the Röt Clay which could result in integrity issues with both the caprock at the near wellbore and the casing/cement interface. Perforating in the high permeability upper zone should be avoided.

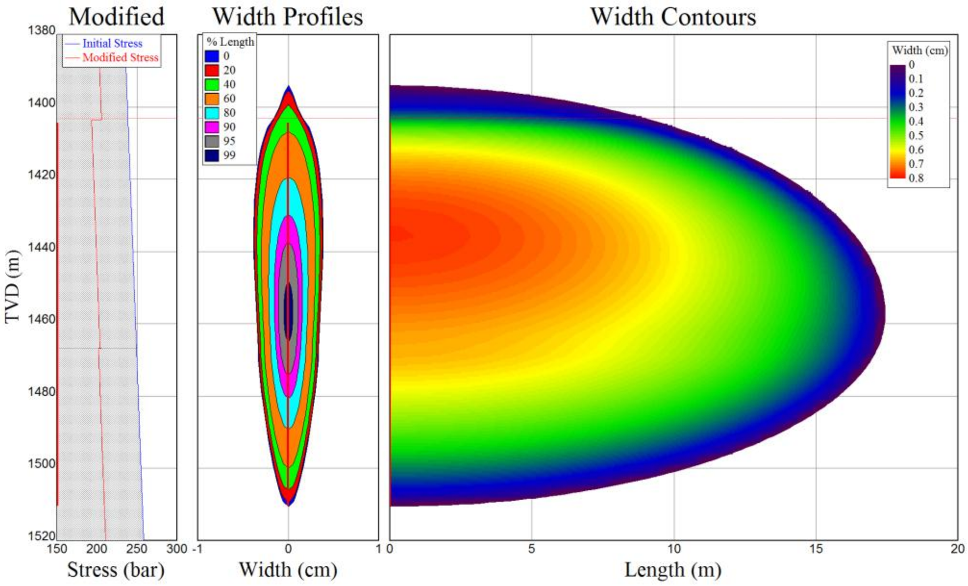
Figure 6.17: Fracture in Zone L3B



6.2.10 Fracturing L1B and L1A

An assessment has also been made of fracturing when perforating 185m across the L1B and L1A zones, as shown in Figure 6.18. This has a limited length of 17m and again it is contained within the zones. Note that the total number of perforations is limited by the software to 2000.

Figure 6.18: Fracture Across L1B and L1A (185m Perforations)



However 185m of perforations at six shots per foot (6spf) is approximately 3,640 perforations – so the fracture would in reality be even shorter.

6.3 Perforating Strategy

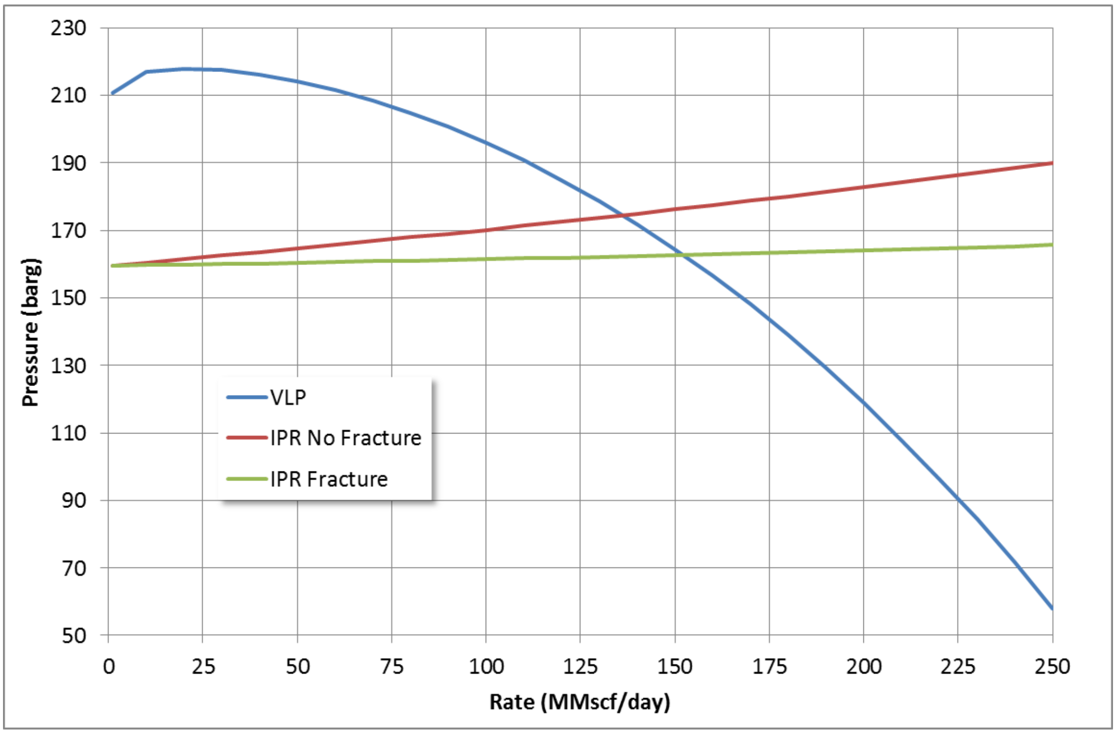
The perforation strategy must achieve the following criteria:

- allow the injection of 2.68MTPA of CO_2 into the Bunter Sandstone Formation;
- prevent the fracturing of the formation outside the confines for the Bunter Sandstone thus maintaining store integrity; and
- cater for future perforating should existing perforations become plugged or collapse or the near wellbore becomes damaged.

Based on the inflow performance and fracturing analysis shown earlier, it is suggested that a minimum of 185m of perforating be carried out across zones L1A and L1B. The perforations should be 20m to 30m above bottom hole. In addition, to allow additional perforating to be carried out at shallower depths in the Bunter, this will also provide ample separation between adjacent injection wells which will be at 55° degrees deviation away from one another. Comparing this scenario with both non-fractured and fractured formation shows that sufficient injectivity can be achieved. The calculation for the system curve shown in Figure 6.19 includes the following assumptions:

- average permeability across L1B and L1A is assumed to be 150mD; and
- dimensionless conductivity of fracture for fractured well case is 10.

Figure 6.19: System Curve for Non-Fractured and Fractured Comparison



This solution provides sufficient injectivity, minimises fracture propagation should it occur and allows for further perforating should it be required at a later date.

7 Flowline Well Interaction

7.1 CO_2 Flow Control Sequence

Figure 7.1 is a schematic of the main CO_2 process flow scheme at the offshore storage facility from the riser up to and including the wellhead.

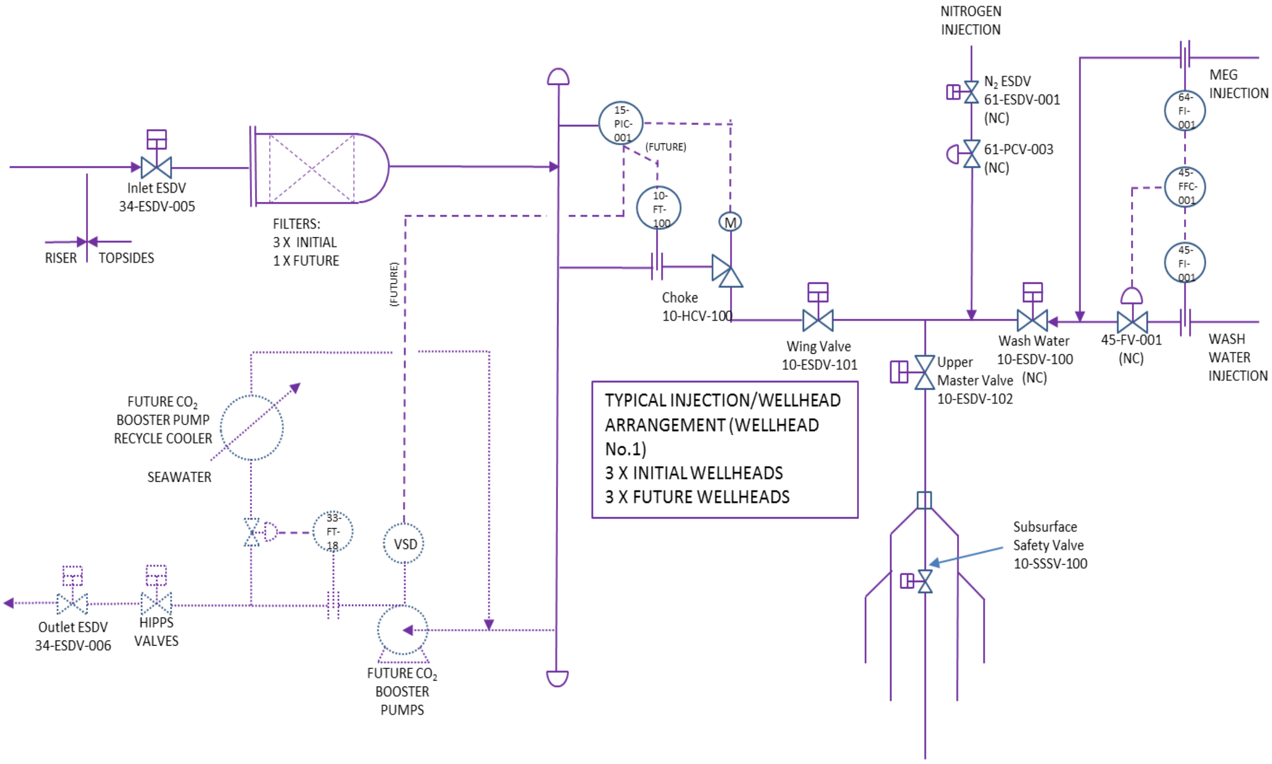
Dense phase CO_2 is received at the platform through a riser up to the injection manifold. During years 1 to 5 the arrival pressure is controlled at the injection manifold located on the platform by a master pressure controller 15-PIC-001 (first load flow rate ranges from 0.58MTPA to 2.68MTPA). As the flow rate increases from year 5 onwards, necessitating the requirement for CO_2 Booster Pumps Onshore at Barmston, arrival pressure at the platform becomes a function of the pressure controller at Barmston (33-PIC-018) and the master pressure controller at the platform (15-PIC-001). Both pressure controllers will be configured to ensure that the operating pressures in the offshore pipeline do not exceeded Maximum Allowable Operating Pressure (MAOP). Pressure and flow rates will vary throughout the life of the facility within the design parameter ranges.

If the Barmston pumps are not operational; bypassed during first load or turndown operation, the injection manifold pressure at the platform as well as the upstream subsea and onshore pipeline is controlled by the platform master pressure controller 15-PIC-001 alone.

The CO_2 fluid flow to the individual well is controlled by six individual choke valves 10-HCV-100/200/300/400/500/600 of the particular well in conjunction with injection manifold pressure controller 15-PIC-001. When a particular well, Wellhead No. 1 for example is under CO_2 injection, the wash water Emergency Shut Down Valve (ESDV) must be closed and also the nitrogen supply must be closed.

A connection to the Future CO_2 Booster Pumps (04-PU-330033-A/B/C-D200) is provided upstream of the manifold. From year 10 onwards, the flow of dense phase CO_2 to the offshore storage facility will be up to a design maximum of 17MTPA and a portion of the CO_2 will be transported to additional storage facilities or subsea wells via the booster pumps. It is likely that the flow to the wellheads will be fixed using flow control on the individual wellhead lines (10-FY-100/200/300/400/500/600) and the offshore future booster pumps will operate on suction pressure control (at the manifold by 15-PIC-001), which adjusts variable speed drive motors.

Figure 7.1: Overall Process Flow Scheme (Major Control Loops)



7.2 Process Systems

The process systems of the offshore storage facility of the White Rose Carbon Capture and Storage Project include the following:

7.2.1 CO_2 Reception Facilities (Offshore Pipeline and PIG Receiver)

A maintenance valve 34-HV-009 and topsides pipeline riser 34-ESDV-005 are provided to enable isolation of the platform topsides from the pipeline in the event of an emergency, for example, low pressure is observed at the CO_2 injection manifold.

Pressure transmitter, 34-PT-042, equipped with high and low alarms, and temperature transmitter 34-TT-017, are provided to allow operations to monitor the process conditions during topsides depressurisation, or re-pressurisation. During re-pressurisation the temperature will be low due to the pressure drop across the 34-HV-009 bypass valve. Operations will control the rate of depressurisation, or re-pressurisation, to ensure minimum metal temperatures are not breached. In addition to 34-PT-042, the pressure transmitter 34-PT-043 (equipped with high and low alarms) downstream of 34-ESDV-005 may be used for pipeline ESD valve leak testing purposes.

When conducting PIG operations, the temperature and pressure transmitters upstream and downstream of the throttling valve, 34-HV-011 (34-TT-018, 34-PT-043, 34-TT-019 and 34-PT-045 with high and low alarms) enable operations to adjust the throttling rate to stay within the required operating temperature and pressure parameters.

Differential pressure transmitter 35-PDIT-031 provides confirmation that the PIG is not stuck in the minor barrel. 35-PT-032 (high operating pressure range) and 35-PT-033 (low operating pressure range) will be used by operations to confirm that the PIG trap is completely depressurised prior to opening of the trap door. Any trapped pressure will be observed and a high pressure alarm is provided. The PIG receiver end closure is provided with a mechanical pressure safety interlock to prevent opening until fully depressurised.

7.2.2 CO_2 Filtration

A differential pressure transmitter (32-PDIT-016) across all filters is provided to monitor filter operation. The pressure and temperature instrumentation downstream of the filters 32-PI-019/020/021 and 32-TT-001/002/003 allow operations to control the rate of filter depressurisation to ensure minimum metal temperatures are not breached (a low temperature alarm is provided for each transmitter); see Section 7.2.6.

Each filter inlet isolation valve 32-XV-001/005/009 may be operated through the ICSS system or when the platform is unmanned, supervisory control is available from the NGCL control centre SCADA (Supervisory Control And Data Acquisition) system. The isolation valve is motorised and provided with limit switches, which provides feedback to the operations team.

A common filter bypass 32-HV-025, locally operated, is provided at full line size. A ‘soft’ valve interlock, in the ICSS, will be included to ensure that the flow within the CO_2 transportation system is uninterrupted, when taking a filter out of service for maintenance; a filter can only be taken offline when another filter is brought on stream. This also prevents inadvertent closure of a filter from through the ICSS or SCADA system.

The quick opening end closures will be fitted with mechanical safety devices to ensure filter is fully depressurised before the closure can be opened.

7.2.3 CO_2 Injection Manifold and Wellheads

Flow rates to individual injection wells will be displayed by 10-FY-100/200/300. The chokes 10-HCV-100/200/300 will be modulated by 15-PIC-001 to ensure the upstream CO_2 system remains in the dense phase at all times (above 90 barg) and also pressure does not become too high (pressure is to remain below the MAOP of the onshore and offshore pipelines). Failure of this control loop causing the chokes to open could lead to vaporisation of the CO_2. It is predicted that this endothermic phase change could result in low temperatures; note that in an endothermic reaction, energy is taken in from the surroundings. A low pressure trip from 15-PT-002 (located on the injection manifold) is therefore provided to shut-in the wellheads where backpressure control is lost and low pressure is detected. A low temperature alarm from 15-TT-001 is located just upstream of the manifold.

The platform controls (ICSS) will automatically regulate the platforms operation within the desired safe limits of the operating envelope. In unmanned mode, all offshore pipeline, platform and storage facilities can also be remotely operated via a SCADA system located at the onshore NGCL control centre.

For future platform wellheads the control arrangement will be identical to the three initially installed wellheads. For the future subsea wellheads the control philosophy will be the same as for the initially installed platform wellheads however the design of these is outside the scope of the FEED.

It is likely that there will be an interface between the downhole instrumentation and the control system at the wellhead. The following instrumentation is likely to take measurements and be relayed back to the control system:

- downhole pressure and temperature measurement;
- inner annulus pressure;
- outer annulus pressure; and
- choke outlet pressure.

7.2.4 Future CO_2 Booster Pumps

When CO_2 injection into the Endurance storage reservoir is no longer operable, the CO_2 booster pumps will export the CO_2 to another facility.

The pump control shall be fully developed during the detailed design phase but is expected to be on future booster pump suction pressure control. The pressure at the manifold will be controlled by modulating the variable speed drives of the future CO_2 booster pumps. The flow to the wells will be fixed on flow control and will be governed based on factors such as the number of available wells, pipeline operating pressure and reservoir pressure. Any surplus flow will be routed to future storage sites outwith the Endurance aquifer location via the future CO_2 Booster Pumps. The use of flow control at the pumps is not preferred as this may lead to potential pipeline packing or unpacking due to flowmeter inaccuracies.

When operating in this mode, in the event of a low flow/no flow scenario from onshore, and falling system pressure, the pressure controller, 15-PIC-001 (on the manifold) will reduce pump speed and bring pumps offline as necessary to maintain system pressure. However, choke flow controller 10 FY-100/200/300 will then open the choke valves to maintain flow to the wells, reducing system pressure again and potentially causing phase separation in the pipeline. Therefore 15-PIC-001 should be configured to override (via a low signal selector) 10-FY-100/200/300 at the low pressure alarm setting 15-PIC-001 L and close the choke valve to prevent phase separation in the pipeline.

Assuming that similar pumps as those used in the onshore pumping station are installed, the shut in head pressure of the pumps will be higher than the export line design pressure (200barg). Hence mechanical HIPPS valves are envisaged on the pumps common discharge to protect the pipeline from overpressure in the event of a blocked discharge.

The pumps will be tripped and suction, discharge and recycle ESDVs will be closed on low inlet pressure (from 33-PT-050/054/058) or low flow (from 33-FT-017/019/021). In the event that the low pressure trip from 15-PT-002 is activated, the pump will trip and only the suction and discharge ESDVs will be closed.

The CO_2 booster pumps recycle cooler is required to remove the heat from the CO_2 generated whilst the pumps are operating in recycle mode at commissioning/proving (which would otherwise heat and potentially vaporise the CO_2 and exceed system design temperatures). Only one booster pump will be commissioned/proved at a time. During commissioning/proving, flow controller, 33-FIC-018/020/022 will open the recycle flow control valve. The temperature of the CO_2 exiting the recycle cooler and returning to the inlet of the CO_2 booster pumps will be controlled by 33-TIC-017 which will modulate the flow of seawater coolant via 33-TV-017 until the process set point is reached. High and low temperature alarms on the CO_2 outlet provide indication that there is insufficient seawater or overcooling is occurring.

The CO_2 booster pump recycle cooler outlet pipework is provided with a temperature transmitter 33-TT-018 on the CO_2 side with a high-high temperature trip to stop the CO_2 booster pump which is operating in recycle. This ensures downstream equipment design temperatures are not breached in the event sufficient cooling duty is not provided.

Due to the type of recycle cooler installed (shell and plate type), a leak from the high pressure CO_2 side to the low pressure seawater side is unlikely, however a high pressure trip from 45-PT-010 initiates closure of the seawater inlet and outlet ESDVs (45-ESDV-001/002) to protect the low pressure side. In addition to this action, both the seawater lift pumps and temporary wash water package will be tripped. A high pressure alarm (45-PI-011) acts as a pre-warning to this trip.

7.2.5 Water Production

If deemed to be required to decrease the downhole pressure then future water production from the reservoir will flow to the produced water caisson via flow transmitter 43-FT-001. The future design of the water production flowlines shall include one ESDV in each incoming line (43-ESDV-001 and 43-ESDV-002). A sampling facility for analysis of the incoming stream is also specified to monitor the CO_2 content, as breakthrough of CO_2 could lead to corrosion issues and degradation of the topsides pipework.

7.2.6 Process Venting & Process Isolation

Pressure and temperature indication has been provided at various locations in the process to allow conditions to be monitored during depressurisation. Venting is a manual activity intended to release CO_2 inventory for various reasons. It can be initiated from the remote (onshore) control centre. The upstream valve is Locked Closed (LC), due to the commercial implication of accidental release of inventory, which has already been metered at the Barmston Pumping Facility.

The location of ESDV, SDV, motorised and manual isolation and positive isolation points are primarily based on meeting the need for safe isolation of pipeline, equipment and instrumentation for maintenance, operation or inspection purposes due to the high operating pressures of the system and the hazardous nature of CO_2. Throughout the offshore storage facility, isolation is provided based on an assessment of the fluid service and flange rating of the equipment/pipework.

Actuated shutdown valves have been considered as a means for providing maintenance isolation, but only if they are designated as tight shut-off, in line with the relevant design code and have a fail close configuration. The shutdown valve is located furthest away from the pipeline/source of pressure that the system is being isolated from.

Generally, pressure instruments (including differential pressure tappings on flow instruments) utilise integral double block and bleed valves in CO_2 service. Isolation shall be met with piping valves not instrument valves.

8 Operational Support

The key roles and responsibilities of the storage operator of the offshore CO_2 storage facility will be as follows:

- acceptance of the CO_2 at the correct specification from the offshore pipeline system.; and
- commissioning of the offshore storage facility, to ensure that the operation is stable and reliable, without trips or upsets.

8.1 Storage Site Operations and Maintenance Overview

The platform is a NUI and hence all offshore facilities will normally be remotely operated and controlled from the NGCL control centre (located onshore). Communication to the NGCL control centre will be via satellite transmission. However, when operated in 'manned mode', the platform will be operated locally from the Human Machine Interface (HMI) within the platform's Local Equipment Room (LER).

Platform visits will be required for the following activities:

- planned maintenance and / or testing of equipment and instruments;
- re-supply of fuel, water, MEG and any other chemicals and consumables;
- well sampling and instrument calibration;
- statutory inspections and surveys;
- well interventions, including wireline work;
- well water wash activities;
- major maintenance during platform shutdown; and
- PIG operations.

The frequency for platform visits necessary to facilitate the above activities will be every 6 to 7 weeks when all six platform wells (future requirement) are fully operational For the initial phase when only three wells are drilled and available, visits will be less frequent e.g. every 14 to16 weeks. Platform visits are dayshift visits only, with transport to / from the platform via helicopter. Activities taking a number of days will require morning and evening helicopter transport each day. Staying on the platform overnight is an emergency measure only (in response to weather conditions for instance).

When extended work campaigns are planned, it may also be feasible to have a floating support/accommodation vessel moored alongside the platform to reduce the logistics of shuttling people to and from the Platform via helicopter. This will be evaluated on a case by case basis by the Operations and Maintenance teams. A suitable 'Walk to Work' system will be a requisite of the support vessel and the Platform will be adequately designed for it.

It is envisaged that the well washing activity (7 day duration) will require platform visits on day 1 and day 7 only, with remote monitoring from onshore in-between.

For any activities requiring relatively large numbers of workers over an extended period (e.g. major maintenance or future platform expansion works including drilling of additional injection wells or the installation of future equipment), a jack-up rig will be used for accommodating workers during these periods.

Unplanned interventions will be arranged as necessary in response to breakdown/failure of platform equipment or systems. The intervention team will comprise of the following core competencies, in addition to the required mechanical, instrument, electrical technician skills to suit the proposed maintenance work:

- Offshore Installation Manager (OIM);
- Nominated Responsible Person;
- First Aider;
- Radio Operator;
- Helicopter Landing Officer;
- Helideck Assistant;
- TEMPSC Coxswain; and
- Crane Driver.

The core competency requirements are such that a minimum intervention team will comprise of not less than three persons. However, planned visits will be arranged to maximise the number of personnel on each visit in order to complete all planned maintenance tasks and optimise helicopter and standby vessel (if required) logistics. These dedicated maintenance teams would retain the specialised knowledge and history of the equipment, augmented by long-term maintenance agreements with specialist maintenance contractors using specialised procedures.

8.2 Measurement, Monitoring and Verification Plan Instrumentation

A key component of the operations support is the management of the instrumentation required for the Measurement, Monitoring and Verification Plan, which will be installed in the wells. Both surface and downhole instrumentation will be needed as described below.

8.2.1.1 Monitoring of Surface Pressure and Temperature

Sensors for pressure and temperature measurements will be incorporated at the wellhead to provide monitoring of the tubing and annuli. Monitoring of the ‘A’ annulus pressures will indicate if there are any integrity failures of the ‘A’ annulus envelope which is comprised of the completion packer, tubing hanger, upper completion tubing, and individual upper completion assemblies. Monitoring for pressure in the ‘B’ annulus can provide an indication of migration of CO_2 through cement or indicate casing integrity issues.

These sensors will be connected to the platform information bus, which will be powered by platform supplies and will provide semi-continuous high accuracy data. For redundancy, multiple sensors will be deployed as replacement of sensors would require a rig workover.

8.2.1.2 Downhole Pressure and Temperature Gauges

Pressure and temperature gauges installed downhole in each of the injection wells will provide an accurate measure of downhole injection and annulus pressure during the injection phase.

As with the surface sensors, these gauges will be connected to the platform information bus, will be powered by platform supplies and will provide semi-continuous high accuracy data. For redundancy, multiple sensors will be deployed as replacement of sensors would require a rig workover.

The use of distributed fibre optic sensors has been discounted as the sealing integrity of the well is of preeminent importance in the selection of downhole temperature and pressure monitoring technology. Technologies that require feed-through wires such as Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) are particularly problematic as these cables are potential leakage paths in the long-term after well abandonment. For this reason and other inherent reliability issues associated with DTS and DAS these technologies are not considered optimum for monitoring purposes on Endurance.

Furthermore, flow profiling by slick line or electric line production logging may be used if well performance is substantially different to that predicted. Distributed temperature and strain measurement is unlikely to be to provide unique definition of thermal fracturing which is expected to occur gradually during the initial injection period and given that well performance will primarily be controlled by the reservoir and layer properties deeper in the reservoir and beyond the near wellbore region.

8.2.1.3 Injection Allocation Meters

Allocation meters will be installed to measure the volumes of CO_2 injected into each well. These meters will be installed upstream of the well chokes and therefore can be relatively easily repaired or replaced if they fail.

9 Glossary

Abbreviations	Meaning
API	American Petroleum Institute
barg	Bar gauge
CCS	Carbon Capture and Storage
CO_2	Carbon dioxide
Cr	Chromium
CPL	Capture Power Limited
°C	Degrees Celsius
DECC	Department of Energy and Climate Change
DIFFS	Deck Integrated Fire Fighting System
ESD(V)	Emergency Shutdown (Valve)
FEED	Front End Engineering Design
HMI	Human Machine Interface
ICSS	Integrated Control and Safety System
IID	Intelligent Inspection Device
IPR	Inflow Performance Relation
kg/h	Kilograms per hour
KSC	Contract made between CPL and NGCL
LC	Locked closed
LER	Local Equipment Room
MAOP	Maximum Allowable Operating Pressure
MDT	Modular Dynamic Tester
MEG	Mono Ethylene Glycol
m^3/h	Cubic Metres per Hour
mm	Millimetres
MTPA	Million Tonnes Per Annum
MW	Mega Watt
NGCL	National Grid Carbon Limited
NUI	Normally Unmanned Installation
OPP	Oxy Power Plant
O_2	Oxygen
PIG	Pipeline Inspection Gauge
ppm(v)	Parts Per Million (Volume)
PREN	Pitting Resistance Equivalent Numbers
RFT	Repeat Formation Tester
SCADA	Supervisory Control And Data Acquisition
TEMPSC	Totally Enclosed Motor Propelled Survival Craft
TVDSS	True Vertical Depth Sub-Sea
T&S	Transportation and Storage
VIT	Vertical Interference Tests
VLP	Vertical Lift Performance
VSAT	Very Small Aperture Terminal
WHT	Wireline Head Thermometer

WR	White Rose
Term	**Explanation**
Bunter Sandstone	Sandstone deposits containing colourful rounded pebbles, widespread across central Europe
Caisson	A vessel with the bottom end open through which water continuously drains into the sea
Carbon capture	Collection of CO_2 from power station combustion process or other facilities and its process ready for transportation
caprock	A harder or more resistant rock type (like sandstone) overlying a weaker or less resistant rock type
Completion	The conduit for production or injection between the surface facilities and the reservoir
Christmas Tree	Often called a production tree or dry 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
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
Deviated Well	A well drilling operation where the drill bit is deflected at an angle from the vertical toward a specific target
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 will 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
Endothermic	A reaction, energy is taken in from the surroundings
Enthalpy	The amount of heat content used or released in a system at constant pressure
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
Integrated Control and Safety System	Regulates the production process using real-time data acquisition to guarantee the smooth operation of the equipment and ensure environmental and personnel safety
Injection well	Deep subsurface rock formations identified for long-term storage
Jacket	A welded tubular steel frame with tubular chord legs supporting the deck and the topsides in a fixed offshore platform
J-tube	A conduit that has the shape of the letter "J" that is attached to the platform
Joule-Thomson cooling	When a real gas expands from high to low pressure at constant enthalpy (thermodynamic potential)
Joule-Thomson effect	Describes the temperature change of a gas or liquid when it is forced through a valve or porous plug while kept insulated so that no heat is exchanged with the environment
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
Layer	Also known as rock layers and strata; is a bed of rock that is visually distinguishable from adjacent layers
Linepack	The volume of gas occupying all pressurised sections of the pipeline network
Lithology	Study of rock-formation

MFrac	Design and evaluation simulator software for fracture design and treatment analysis
Mpwri	Produced water reinjection simulator software designed for evaluating the effects of injecting large volumes of fluid over long periods of time with fracture efficiencies approaching zero
ND	Nominal diameter
Nitrogen quads	Manifold pack holding nitrogen cylinders connected to one outlet
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
Permanent Packer	A device that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the wellbore. It is constructed of materials that are easy to mill out
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
Phase envelope	The behaviour of a gas at different phases represented as a function of pressure and temperature
PREN	Also known as PRE numbers are a theoretical way of comparing the pitting corrosion resistance of various types of stainless steels, based on their chemical compositions; they are useful for ranking and comparing the different grades
PROSPER	A software tool used to model reservoir inflow performance for single, multilayer, or multilateral wells with complex and highly deviated completions, optimising all aspects of a completion design including perforation details and gravel packing. The design and evaluation of the different well completions can be studied
Riser	Conduit to transfer materials between the seafloor and facilities atop the water's surface
Reservoir	Containment in suitable pervious rock formations located under impervious rock formations usually under the sea bed
Seal Mandrel	A device which allows access to the well without removing the packer
Supervisory Control And Data Acquisition	Or SCADA. A system operating with coded signals over communication channels to provide control of remote equipment
Two-phase	A region with gas and liquid coexisting
Very Small Aperture Terminal System	A two-way satellite ground station or a stabilised maritime VSAT antenna with a dish antenna that is smaller than 3 meters. VSATs access satellites in geosynchronous orbit to relay data from small remote earth stations (terminals) to other terminals (in mesh topology) or master earth station "hubs" (in star topology)
Young's Modulus	A mechanical property of linear elastic solid materials. It measures the force (per unit area) that is needed to stretch (or compress) a material sample
VISAGE	A finite-element geomechanics simulator which models problems to enable the planning and mitigation of risks
Wellhead	The component at the surface of a well that provides the structural and pressure-containing interface for the equipment
Wellbore	A borehole; the hole drilled by the bit
Wirelines	Electric cables that transmit data about the well
White Rose Transport and Storage FEED Project	CPL and NGCL have entered into a key sub-contract agreement where NGCL will perform this project which will meet that part of CPL's obligations under the FEED Contract which are associated with the transport and storage assets